

AR73

INTERNATIONAL ENERGY
OPPORTUNITIES

Eurogas

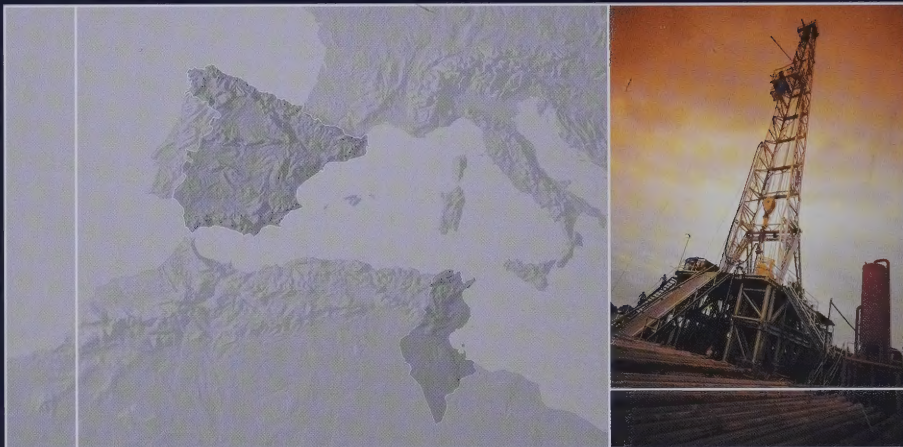
EUROGAS CORPORATION



2004 ANNUAL REPORT

SPAIN Natural Gas Storage Development

TUNISIA Offshore Oil Development



Eurogas Corporation is a Calgary, Canada-based company whose common shares trade on the TSX-Venture Exchange under the symbol EUG. Eurogas is focused on creating long-term value through the development of high-impact energy projects. The Corporation is developing a major underground natural gas storage facility in Spain, and conducting exploration programs for oil and natural gas on concessions on- and offshore Tunisia.

The Annual and Special Meeting of Eurogas Corporation will be held at 2:30 p.m. (Mountain Daylight Time) on May 26th, 2005 in the Viking Room of the Calgary Petroleum Club, 319-5th Avenue S.W., Calgary, Alberta, Canada. Shareholders are encouraged to attend. Those unable to attend should complete and return the form of proxy.

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From left to right: M. Jaffar Khan, *President & CEO*, Bruce Sherley, *Executive VP & COO*
Andrew Constantinidis, *VP & CFO*, Julio Poscente, *Chairman of the Board*, Jim Batchelor, *VP, Exploration*

LETTER TO SHAREHOLDERS

Eurogas Corporation was organized in 1995 to execute a business plan entailing the acquisition and development of diverse, high-impact energy projects in Spain, Tunisia and Russia. Success in any one of these projects would result in extraordinary growth for the Company.

In Russia, we negotiated a partnership agreement aimed at the development of a massive natural gas/condensate field in Western Siberia. In Tunisia, we acquired large tracts of land over internally-generated geologic concepts and known oil accumulations. In Spain, we identified an opportunity to develop a world-class, underground natural gas storage facility and, to that end, acquired the rights to the abandoned Amposta oil reservoir. Recognizing the need for a reliable and non-dilutive source of capital to systematically advance these projects, we then acquired non-operated producing oil and natural gas properties in Western Canada.

Adhering to the underlying premise that the success of Eurogas was not dependent on bringing all three projects to fruition, management increasingly focused on the most responsive projects. As investment risks in Russia grew, we decided to sell our interests in that country and to redeploy cash realized from the sale to our projects in Tunisia and Spain. Moreover, as our projects in Tunisia and Spain matured, it became increasingly evident that the Company's Canadian properties and production held potential for greater shareholder value if used as a nucleus for a new, independent, full-cycle oil and natural gas company. Accordingly, we organized a new company – Great Plains Exploration Inc., under independent management. In June 2004, virtually all of Eurogas' Canadian properties were rolled into Great Plains; the shares of Great Plains were then distributed to Eurogas shareholders.

Following the reorganization of the Eurogas assets, we completed a major 3-D seismic program in Tunisia to delineate two known oil accumulations on the Company's offshore Sfax permit. Concurrently, we launched the pre-development program on the Company's Amposta underground natural gas storage project located offshore Spain's east coast. Following reprocessing of vintage 3-D seismic over the Amposta structure and completion of the Design Basis Memorandum, in December 2004 we drilled the Castor #1 well. It proved Eurogas' technical analysis indicating the existence of an extensive system of undrilled highs (attic areas) on the Amposta structure, which house significant volumes of recoverable oil. During March 2005 we completed a new high-resolution 3-D seismic program over the Amposta structure to better define the size of these attic areas. These data are required to accurately locate wells required to drain remaining oil from the reservoir before converting them to gas injection/retrieval wells. The second well in our Amposta development program is planned for drilling during the fourth quarter of 2005.

Underground natural gas storage is a critical infrastructure requirement for Spain's rapidly growing natural gas industry, and Amposta is capable of providing 25 percent of that requirement. You will find a complete description of the Amposta project beginning on page 4 of this report.

In Tunisia we are actively engaged in exploration programs on our onshore El Hamra permit in southern Tunisia and our Sfax permit offshore in the Gulf of Gabes. On the El Hamra permit, in which Eurogas holds a 20 percent interest, Eurogas was carried through the drilling of the EH-1 well.

On the Sfax permit, a 350-km² 3-D seismic program was shot in 2004 over two known oil accumulations in order to delineate the structures and identify the optimum drilling location for a well planned for the fourth quarter of 2005 or early 2006. The Sfax permit lies in the shallow water of Tunisia's Gulf of Gabes and is located on a hydrocarbon fairway with four proven hydrocarbon systems on the permit. Adjacent to the permit there are seven producing fields that have combined proven reserves in excess of 500 million barrels of oil and 2 trillion cubic feet of gas. In 2004, Eurogas completed a high-resolution 3-D seismic program over these oil accumulations to define their size and to determine optimal drilling locations to develop the field. Moreover, 12 additional prospects with combined oil potential in excess of 1.5 billion barrels have been identified on the permit. Substantial geologic/geophysical studies are required to develop these additional prospects.

Eurogas holds a 45 percent interest in the highly-prospective Sfax permit. Atlas Petroleum Exploration Worldwide Ltd. (APEX) of Houston, Texas has a 55 percent interest and is operator for the partnership.

The Company's 2004 capital expenditures, of approximately \$9.3 million were funded by cash received from the sale of our Russian properties and an oversubscribed Rights Offering. Eurogas has established a \$6 million line of credit with Dundee Corporation. This line of credit allows Eurogas to move forward with key elements of the pre-development phase of the Amposta project.

Eurogas has entered a new and dynamic phase of growth with the start of development of the Amposta underground

natural gas storage facility in Spain and the development of semi-proven offshore oil in Tunisia. It is with great pleasure that I introduce the management team that will lead Eurogas through this important growth phase.

Mr. M. Jaffar Khan has been appointed President and C.E.O. of Eurogas. Mr. Khan brings to Eurogas over 35 years of experience in the international energy business, including leading the development of a \$600 million independent power project in Pakistan. I had the pleasure of working with Mr. Khan from 1971-1991 in building the very successful international oil and gas exploration company Canada Northwest Energy Ltd.

Mr. Bruce Sherley, P.Eng., joined Eurogas in 2000, bringing with him over 25 years of operating experience, both domestic and international; he will continue as Chief Operating Officer of Eurogas. Mr. Sherley has also been appointed President of Eurogas International Inc., our international operating company.

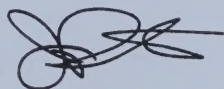
Mr. Andrew Constantinidis, a Vice President of Eurogas, becomes our Chief Financial Officer. Mr. Constantinidis has extensive international experience with financial institutions, including Citibank in Hong Kong and Deutsche Bank in Singapore, and has downstream oil and gas experience working for Mobil Oil in Hong Kong and China.

Mr. Recaredo del Potro of Madrid has been appointed President of Escal UGS S.L., the Spanish operating company developing the Amposta gas storage facility. Mr. del Potro brings over 30 years of experience in the oil and gas industry in Spain and the environmental regulatory field in South America and in Spain.

I will remain Chairman of the Board and continue to be actively involved in an advisory capacity in the continuing development of Eurogas.

Major projects, whether domestic or international, require patience and dedication on the part of both management and shareholders. We have never wavered from our objective of bringing at least one of our projects to fruition. We have made measurable progress each year, culminating in the exciting advances in the Amposta underground gas storage (UGS) project during 2004. I thank the Company's shareholders for their patience; our major shareholder, Dundee Corporation, for its unwavering support; and my fellow members of the Eurogas team in Calgary, Madrid and Tunis for their superb work through the year.

On behalf of the Board of Directors,



Julio Poscente
Chairman of the Board
March 29, 2005

AMPOSTA UNDERGROUND NATURAL GAS STORAGE PROJECT



The Amposta underground natural gas storage (UGS) facility is required to address the urgent need for natural gas storage in Spain. The natural gas market in Spain is experiencing rapid growth, with consumption expected to double by 2011. The Amposta UGS facility, utilizing the abandoned Amposta oil reservoir, will create natural gas storage sufficient to meet 25 percent of Spain's future requirements. By providing a dedicated source of high-deliverability natural gas, Amposta will provide security of supply and meet seasonal and daily gas peak demand for industrial and domestic customers.

The Amposta reservoir, which was placed on production by Shell Oil in 1973, had an estimated 100 million barrels of crude oil-in-place, with 56 million barrels of oil produced before its abandonment in 1989. The location and geometric features of the Amposta structure, coupled with the petrophysical properties of the reservoir rock, the large storage capacity and active water drive, combine to provide all the elements required for a world-class UGS facility. Amposta will have storage capacity of 1 billion cubic metres of working gas and be capable of delivering 25 million cubic metres of gas per day for 40 days sustained.

OFFSHORE AND ONSHORE FACILITIES

The Amposta project's facilities will include an offshore platform, an onshore terminal, a 34-inch sub-sea pipeline connecting the platform to the terminal, and a pipeline connecting the terminal to the Spanish national gas distribution network.

The offshore platform, which will be located in 60 metres of water, will have provision for nine wells. Injection gas will be compressed onshore. Withdrawn gas will be dehydrated offshore, then

Opposite

Left: Drilling activity.

Right: Flow-testing Castor #1 well.

SPAIN NATURAL GAS INFRASTRUCTURE

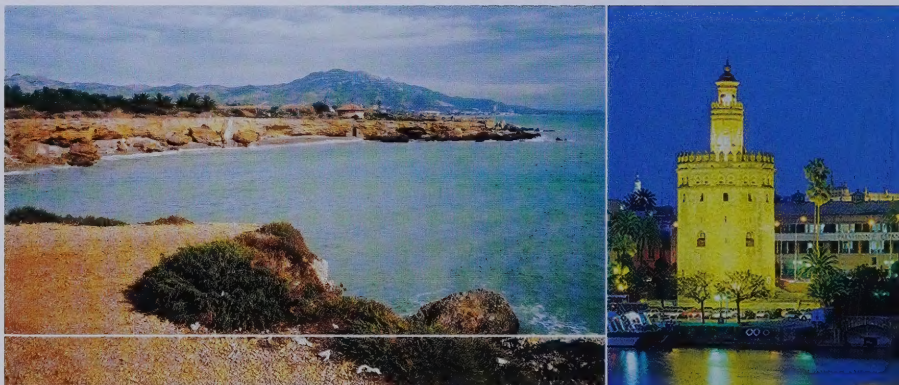


transported onshore for further processing and re-injection into the national gas distribution network.

The onshore terminal will include a compression system for gas injection and a gas treatment system for gas withdrawal. Property has been purchased for the onshore terminal.

The facilities will be engineered to supply gas at their full design rate to the Spanish distribution system within two hours of receipt of notice. The Amposta gas storage operation will be linked directly to the national gas distribution system, which is operated by Enagas.

AMPOSTA UNDERGROUND NATURAL GAS STORAGE PROJECT



SPAIN'S NATURAL GAS MARKET DEVELOPMENT

Spain is transforming itself into a natural gas-powered nation, with consumption growing by 233 percent from 1993 to 2003. Annual consumption is forecast to reach 40 billion cubic metres in 2010 and 50 billion cubic metres in 2015. Spain's profound market evolution has been driven by a combination of comprehensive energy deregulation, overall economic growth, recognition of natural gas as a clean fuel, and growth of new supply, as well as expansion of the national distribution network.

Spain has been called "undoubtedly the most liberalized" natural gas market in continental Europe by senior energy industry figures. Examples include the recent commissioning of the nation's first independent natural gas-powered electric-generating station, an 800-megawatt facility, which is indicative of Spain's move towards combined cycle power generation. Domestic gas service is expanding rapidly and plans exist for a pipeline to service the Balearic Islands.

New infrastructure required to meet the growing demand for natural gas in Spain includes: completion of the Maghreb-Spain gas pipeline from Algeria via Morocco in 1997; construction of the Medgaz deep-water pipeline from Algeria to Almeria on Spain's southeast coast (due for completion in 2009); and construction of two new LNG regasification facilities and expansion of the four existing facilities.

SPAIN'S NEED FOR NATURAL GAS STORAGE

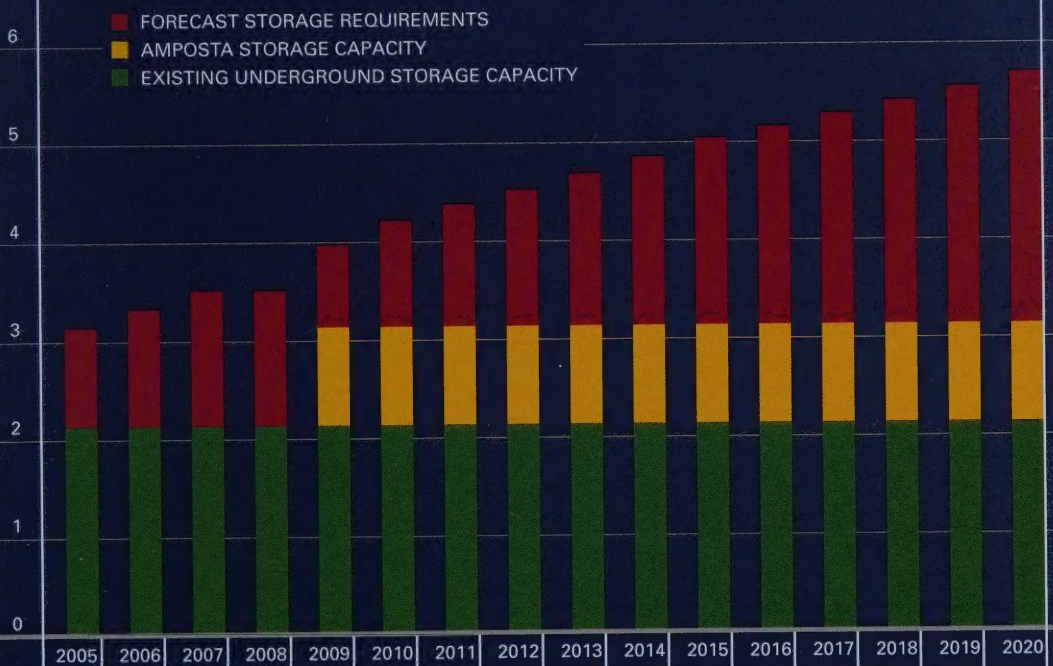
Natural gas storage is a strategic component of a mature natural gas infrastructure. Storage is required to accommodate daily and seasonal fluctuations in natural gas demand, including unforeseen demand spikes, and to mitigate unplanned interruptions in natural gas supply. Storage facilities

Opposite

Left: Shoreline near Amposta plant site.

Right: Lights at night in Seville Andalusia, Spain.

SPAIN'S NATURAL GAS STORAGE REQUIREMENTS FORECAST (Billions of cubic metres)

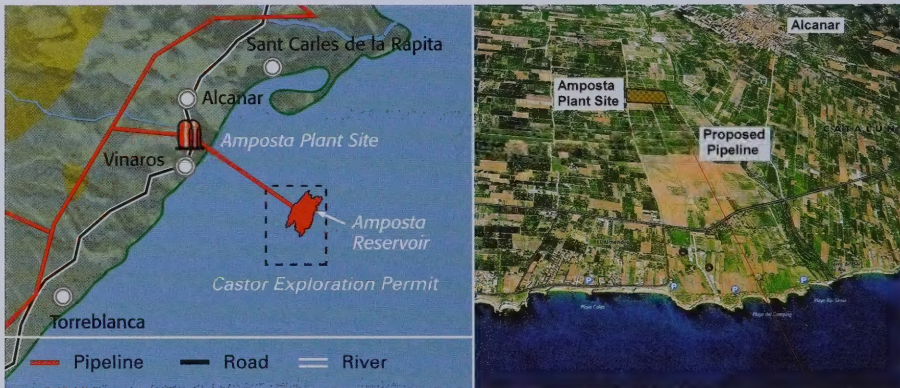


offering high injection and retrieval rates are also needed to smooth short-term volatility in natural gas prices. Spain's Hydrocarbon Law of 1998 recognizes the role of strategic storage in promoting a reliable natural gas system.

Spain has an urgent requirement for large-volume, high-deliverability natural gas storage capability. A Royal Decree

has mandated storage capacity equivalent to 35 days' average national gas consumption. This requirement is not being met by existing storage facilities, which have low deliverability and may not be available for strategic purposes. With natural gas consumption growing at an average rate of 14 percent per year, Spain has a significant and growing natural gas storage capacity deficit.

AMPOSTA UNDERGROUND NATURAL GAS STORAGE PROJECT



THE AMPOSTA ADVANTAGE

Under recent legislation, Royal Decree 1716/2004, natural gas suppliers are required to maintain strategic gas storage equal to 35 days' average demand. The decree also stipulates that, to be counted towards strategic storage, the gas must be deliverable within 60 days. Spain currently has over 2 billion cubic metres of underground storage capacity in two facilities; however, their low deliverability rates reduce the volume qualifying for strategic storage to only 600 million cubic metres. Re-gasification plants have a total of 540 million cubic metres of storage capacity. Including line-pack, Spain's total effective natural gas storage capacity is 1.2 billion cubic metres.

With total gas storage volumes of 1.2 billion cubic metres, Spain has a small deficit of operational storage and effectively no strategic storage. Even if the 60-day rule is overlooked, there is still a strategic storage deficit of 1.2 billion cubic metres. In order to support the continuing growth of gas consumption in Spain, significant investments in gas infrastructure are required. Because of its evident need, natural gas storage is a subject high on the agenda of regulators in Spain. Amposta is the only identified project able to provide strategic natural gas storage needed for security of supply for the eastern portion of Spain's natural gas grid. Even with Amposta, additional storage will still be needed to meet legislated requirements.

Opposite

Left: Regional map showing Amposta onshore plant site, the Castor permit area and the Amposta reservoir.

Right: Satellite photo showing Amposta onshore plant site, the proposed pipeline route and the nearby community of Alcanar.

ILLUSTRATION OF AMPOSTA UNDERGROUND GAS STORAGE PROJECT

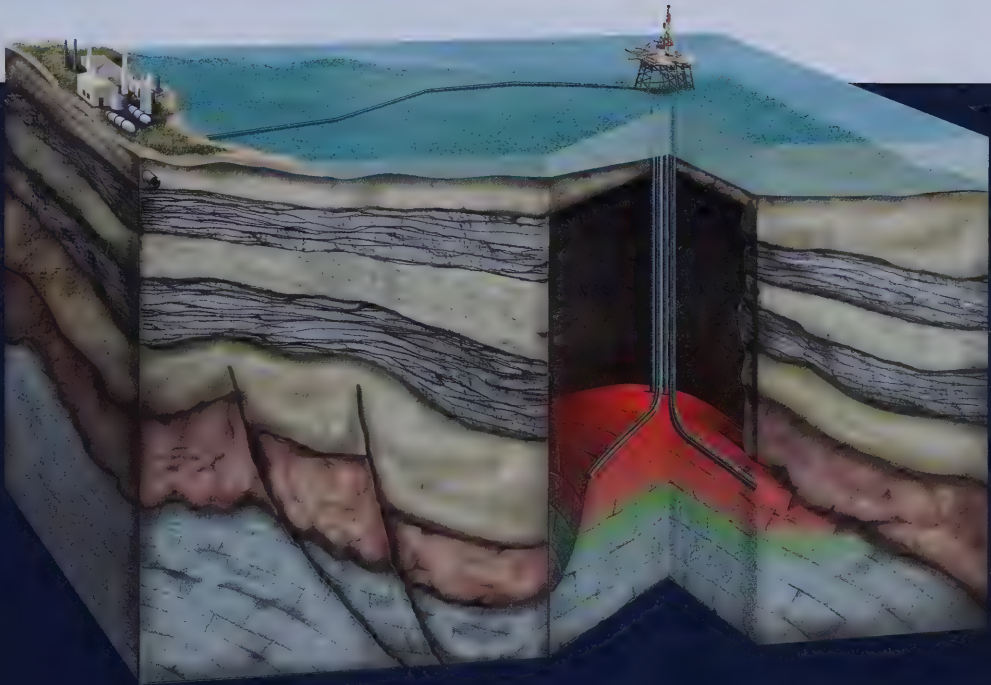


Illustration of the Amposta project showing the Amposta reservoir, injection and withdrawal wells, the offshore platform connected by a subsea pipeline to onshore facilities, which are in turn connected to the national gas pipeline system.

Situated on the industrialized east coast of Spain, Amposta is ideally located to satisfy regional gas storage needs, and would be able to replace any gas shortfall in the Barcelona, Cartagena or Sagunto re-gasification plants, as well as the portion of the proposed Medgaz capacity which will be used in the Amposta market area, and gas that may, in future, be sent to France via the proposed Cataluña-France pipeline.

The Amposta storage facility can play a strategic role in ensuring reliable natural gas supply for Spain. In the event of catastrophic failure in the supply system, the exceptional qualities of the Amposta reservoir would enable a constant deliverability rate of 25 million cubic metres of natural gas per day for 40 consecutive days. This is approximately twice the combined deliverability of Spain's two existing underground storage facilities.

AMPOSTA UNDERGROUND NATURAL GAS STORAGE PROJECT



GENESIS OF THE AMPOSTA PROJECT

In 1995 the planned 1997 completion of the Maghreb natural gas pipeline from Algeria to Spain was announced. At that time, Eurogas recognized the need for UGS capacity and the potential for redeveloping the depleted Amposta oilfield as a major UGS facility. This created an opportunity to position Eurogas ahead of the expected evolution of Spain's natural gas infrastructure and the resulting overall growth of the natural gas industry.

In 1996 Eurogas obtained an interest in the Castor exploration permit, enabling the Company to launch a series of studies to substantiate the suitability of the Amposta reservoir for natural gas storage. The Amposta project was subsequently reorganized under the Castor UGS Limited Partnership, in which Eurogas holds a 72 percent working interest and is managing partner. In addition, Eurogas has 100 percent interest (subject to a 5 percent gross over-riding royalty payable to Castor UGS LP) in any hydrocarbons that may be produced from the reservoir.

In 1997 Eurogas initiated a systematic technical due diligence process, which included geophysical, technical and economic studies. This culminated in the completion of a Design Basis Memorandum in November 2004, and the drilling of the Castor #1 well in December 2004/January 2005. The results have met or exceeded Eurogas' expectations for the Amposta reservoir's integrity and quality. In addition, the Castor #1 well confirmed Eurogas' conclusion that significant volumes of commercial oil volumes remain in an extensive system of attic areas on the Amposta structure.

Eurogas formally presented the Amposta proposal to the Spanish Energy Commission in 2003. The Spanish government recognized Amposta as a valid candidate for natural gas storage and included the project in Spain's national energy plans.

Opposite

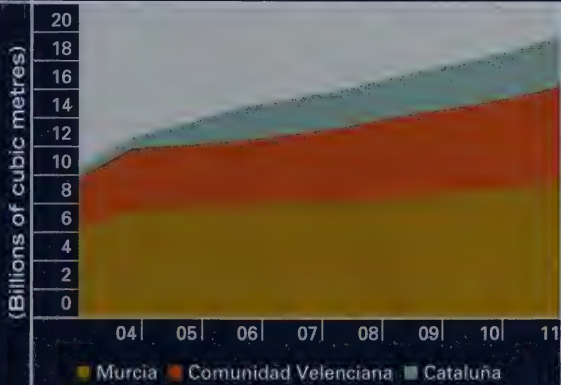
Left: Pipe ready for drilling
Castor #1 well.

Right: Flow testing of the Castor
#1 well in January 2005.

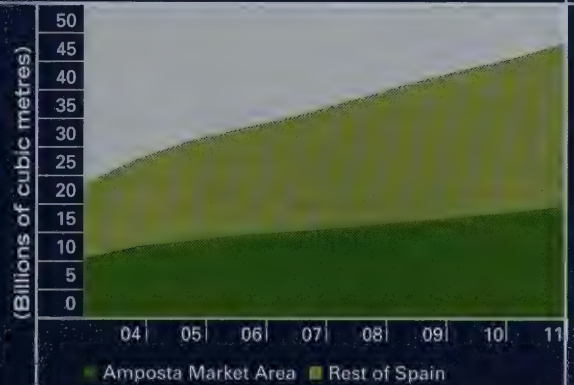
AMPOSTA MARKET AREA



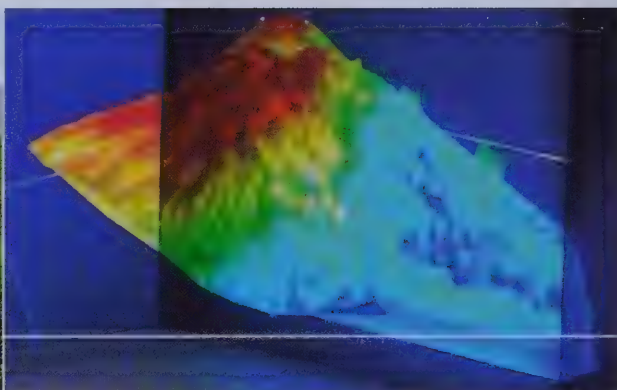
AMPOSTA MARKET AREA GAS DEMAND



AMPOSTA MARKET AREA'S SHARE OF SPAIN'S GAS DEMAND



AMPOSTA UNDERGROUND NATURAL GAS STORAGE PROJECT



THE AMPOSTA RESERVOIR

The Amposta reservoir is technically well-suited for gas storage. The structure is a large, tilted fault block of porous Cretaceous-aged limestone lying at a depth of 1,700 metres below sea level. The reservoir, comprised of fractured and brecciated limestone, is pressure-supported by a large aquifer, and individual wells are capable of delivering natural gas at estimated rates of 3 million cubic metres per day. The reservoir is sealed by 100 metres of shale and tight sandstones, as evidenced by the recovery of 56 million barrels of oil by the previous operator, Shell Oil. The Amposta oil reservoir is 220 metres thick, 5.5 km long by 2.5 km wide, and will hold a minimum of 1.6 billion cubic metres of natural gas if filled to the original oil/water gas contact level.

Shell drilled 12 wells at Amposta starting in 1970. Six were productive, three were uneconomic due to low productivity, and three were abandoned after drilling off-structure. The six successful producers encountered limestones that were porous and brecciated due to karstification that created vugs and caves within the reservoir. The best producing wells tested oil at

rates in excess of 20,000 barrels per day, and the high quality of the reservoir allowed Shell to sustain average production at 23,500 barrels of oil per day for the first three years of production.

In 1982, Shell shot a 75-square-kilometre, 3-D seismic survey that resulted in the drilling of six further wells, three of which targeted the apex of the Amposta structure. At the time, seismic processing did not allow for accurate imaging. As a result, the wells missed the intended crestal position and were drilled off-structure, parallel to the steep western flank. While the quality of Shell's 3-D data was state-of-the-art, subsequent advances in seismic processing resulted in better imaging of the Amposta structure and a significant improvement in understanding the seismic character within the reservoir.

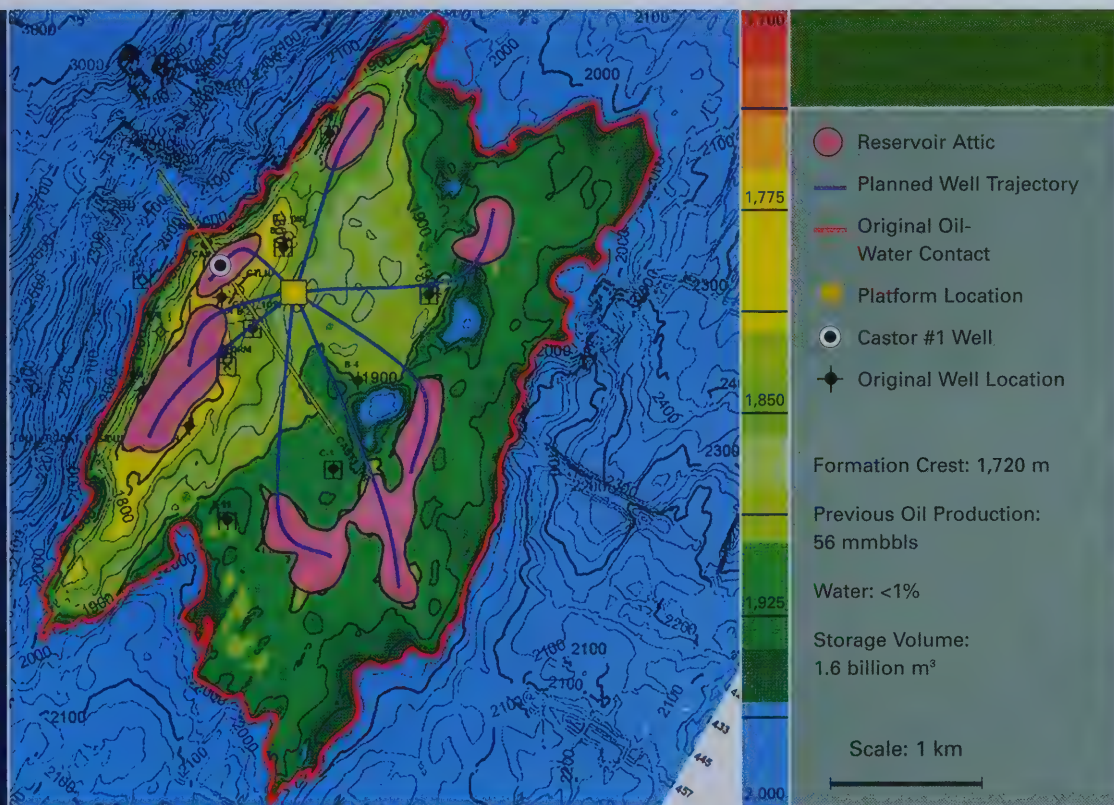
Reprocessing of the original 3-D seismic data and subsequent interpretation have identified five separate structures lying in crestal positions (attics). As a result, the true volume of original oil-in-place could be 40 percent higher than the original estimate of 100 million barrels. It is currently

Opposite

Left: Amposta onshore plant site looking toward Alcanar.

Right: 3-D image of the Amposta structure.

PLANNED WELL LOCATIONS ON THE AMPOSTA RESERVOIR



estimated that the attic regions of the Amposta reservoir could contain up to 35 million barrels of recoverable oil.

In addition, the higher seismic resolution achieved within the reservoir has enabled matching the identified areas of high-porosity karstified reservoir to the specific seismic signal at that horizon depth. This ability to image higher-quality porosity zones will ensure that future wells are drilled in optimal locations to maximize oil withdrawal and gas storage operations. Lateral drilling technology will be applied to complete new wells in the uppermost portions

of these attics, which will result in water-free production of remaining recoverable volumes of crude oil and maximum efficiency of gas storage operations.

2004 ACTIVITIES

In 2004 Eurogas completed the pre-development stage of the Amposta project. The work program included the reprocessing of 1982-vintage 3-D seismic by applying state-of-the-art reprocessing techniques. Eurogas also completed the Design Basis Memorandum and initiated drilling of the

AMPOSTA UNDERGROUND NATURAL GAS STORAGE PROJECT



Castor #1 well in December. This ambitious program was completed at a cost of \$14.5 million, \$5.3 million of which was spent in 2004, and was funded by available working capital and proceeds from a rights offering completed in December 2004.

Eurogas achieved all major objectives of the 2004 work program, including:

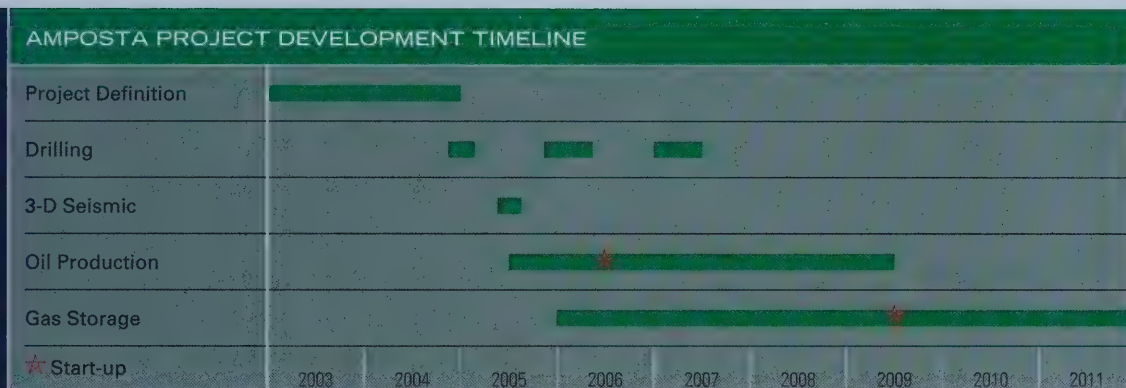
- The Amposta Design Basis Memorandum investigated a series of design alternatives to identify the most cost-effective of the technically-sound options for gas storage development. The level of detail includes general design drawings and layouts sufficient to develop cost estimates and prepare a tender for the detailed Front-End Engineering and Design (FEED) study. The scope of work included assessing the performance reliability of the design and areas of technical uncertainty to be addressed in the FEED study to be performed prior to construction;
- Reprocessed vintage 3-D seismic data acquired over the Amposta structure in 1982 by using state-of-the-art reprocessing techniques;
- Drilled a well into one of the “attic” areas mapped on the Amposta structure to prove the existence of undrilled highs believed to contain significant volumes of recoverable oil.

In January, Eurogas completed drilling and testing operations on the Castor #1 well, which was temporarily plugged at a depth of 1,821 (KB) metres. During test operations the well flowed oil through a restricted choke at a maximum rate of 2,807 barrels per day with a bottom-hole pressure drop of only 3 psi. The Castor #1 well proved the highly porous and permeable nature of the reservoir, and indicated both the probability of a volumetric increase in the size of the reservoir and the existence of significant remaining recoverable oil volumes.

Opposite

Left: Shoreline near Amposta onshore plant site.

Right: Pipe ready for drilling Castor #1 well.



The Design Basis Memorandum to evaluate design alternatives for the Amposta project and to ascertain capital and operating costs was prepared by a joint venture comprised of AMEC PLC of the United Kingdom and Tri Ocean Natchiq Engineering Ltd. of Canada.

Based on the most recent cost estimates, the Amposta UGS project is competitive with European averages in terms of unit cost for storage capacity and deliverability.

UGS is a regulated activity in Spain: the remuneration regime is defined and guaranteed by the national government, and includes a return of capital, return on capital and payment for operating costs. Capital is recovered over 20 years. The return on capital is based on the total investment, and is set at the 10-year government bond rate plus 1.5 percent. This rate is set in January for each year. Operating expenses are also recovered and are adjusted for inflation and efficiency improvements.

As deregulation in the energy industry in Spain and France progresses, the importance of Amposta as a natural gas trading hub could add significant value to the facility.

PLANNED ACTIVITY IN 2005

In 2005 Eurogas will accelerate the Amposta development program, including a state-of-the-art 3-D seismic program over the Amposta structure. The new seismic is required to optimize well locations on remaining attic areas on the structure. Eurogas intends to drill the second well during the fourth quarter of 2005 and accelerate work on an appropriate early production system.

The Company also plans to apply for an Oil Production Concession over the Castor exploration permit area and have opened discussions to move the project through the regulatory process. An environmental study is underway to provide environmental impact analysis for the entire project, including oil production and gas storage. The study is intended to support the development application planned for submission in 2005.

AMPOSTA UNDERGROUND NATURAL GAS STORAGE PROJECT



TAX REGIME FOR OIL RECOVERY IN SPAIN

The economics of oil production are attractive in Spain. The Spanish Corporate Income Tax Act provides a special regime for hydrocarbon entities, which includes the following aspects: depletion allowance, accelerated depreciation, tax-loss carry-forwards and a tax rate of 40 percent. There are no government royalties on hydrocarbons in Spain.

Hydrocarbon companies may reduce their taxable income by use of the depletion allowance, calculated as the larger of:

- 25 percent of hydrocarbon sales up to 50 percent of profits before this reduction, but before offsetting tax losses; or
- 40 percent of profits before this reduction and before offsetting tax losses.

The amount deducted must be invested in oil and gas activities including exploration, investigation and exploitation, or abandonment costs. The period in which to carry out this investment is up to 10 years after the reduction of taxable income or up to four years before the year in which the taxable income was reduced. If the company does not comply with the investment requirement, the amount not invested would become taxable and late payment interest would be due.

Companies carrying out hydrocarbon-related activities can depreciate intangible assets and investigation costs at a maximum annual rate of 50 percent. These costs would include prior geological, geophysical and seismic work, evaluation and development drilling to restore and preserve deposits. Tangible assets are depreciated at normal rates. In certain cases the tax authorities will allow depreciation on a unit-of-production basis.

A company can carry forward previous years' tax losses without any time limit. The maximum amount of loss that can be offset in a year cannot exceed 50 percent of the current year's taxable profit.

Hydrocarbon activities are taxed at a rate of 40 percent; the regular rate is 35 percent.

Opposite

Left: Close-up of Cretaceous limestone.

Right: Pipe ready for drilling.

NATURAL GAS INFRASTRUCTURE REMUNERATION IN SPAIN

The Amposta underground natural gas storage facility will be engaging in activity that is regulated in Spain. Well-developed regulations define the remuneration regime and payments are guaranteed by the national government; however, details and unique features of the Amposta project and the financial regime will be discussed and agreed upon with the authorities.

The remuneration regime for underground natural gas storage contains three components: Return of Capital, Return on Capital and Payment for Operating Costs.

$$\text{Return of Capital} = \frac{\text{Value of Investment}}{\text{Life of Asset (20 Years)}}$$

The Value of Investment is based on actual audited costs, and is incremented each year by 75 percent of the Inflation Rate. Included in the cost are investments carried out within five years prior to the date on which the development permit is granted. The regulations set the Life of Asset for underground storage as 20 years.

$$\text{Return on Capital} = \text{Value of Investment} \times \text{Rate of Return}$$

The Rate of Return is defined as the annual average of 10-year government bonds plus 1.5 percent. This rate is set in January for each year. For 2005 the rate is 4.29 percent + 1.5 percent = 5.79 percent.

At the end of the facility's useful life (20 years for Amposta) there is a reduction in the Return on Capital to 50 percent of what it would otherwise be. The basis for calculation of allowed operating expenses does not change

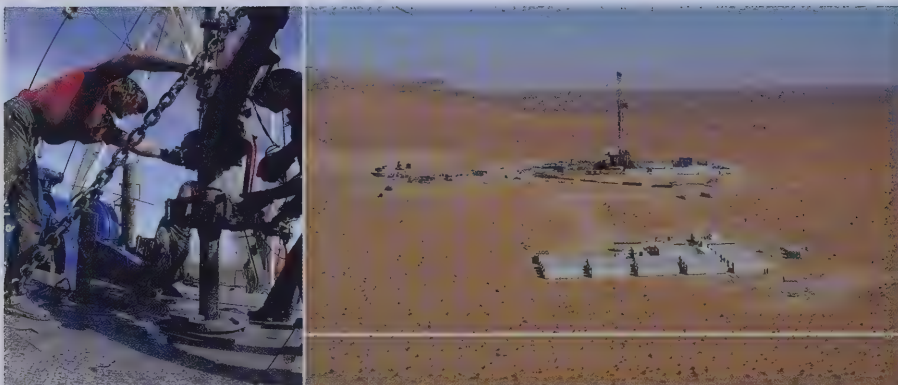
$$\text{Payment for Operating Costs} = \text{Last Year's Payment for Operating Cost} \times (1 + \text{Inflation Rate} \times \left[\frac{\text{Efficiency Index}}{\text{Index}} \right])$$

The Payment for Operating Costs for new facilities is determined in the authorization process. In the following years, the payment for operating cost is adjusted by two factors: the Inflation Rate and an Efficiency Index. The Efficiency Index reduces the inflation rate; it is 0.85 in 2005.

The Inflation Rate is the average of the change in the consumer price index and the industrial price index. The change in the Spanish consumer price index has averaged 2.9 percent over the past decade, which on average has been 1.1 percent higher than the Eurozone index. The change in the Spanish producer price index has averaged 1.8 percent over the past decade. For 2005 the Inflation Rate has been set at 2.5 percent.

A Provisional Economic Regime may be agreed for the period between the granting of the development permit and final start-up, provided this period does not exceed three years. Investments and some operating costs can be included. The inclusion of a Provisional Economic Regime will provide cash flow during the construction phase.

TUNISIA



Since 1998 Eurogas has conducted a systematic exploration program in southern Tunisia, which to date has been unsuccessful. In 2002 our focus shifted from the onshore Triassic/Ordovician prospects to the shallow waters of the Gulf of Gabes, offshore Tunisia. That year Eurogas completed a study over the Sfax permit area and in December 2003 Eurogas (45 percent) and Atlas Petroleum Exploration Worldwide Ltd. (APEX) of Houston, Texas were granted a two-year Seismic Prospecting Permit covering 4,116 km². The seismic permit will be converted to an Exploration Permit in 2005. Upon start of production, a Production Concession, governed by a Production Sharing Agreement, will be granted over the production area.

Seven of Tunisia's largest oil and gas fields, with total proven reserves of 500 million barrels of oil and over 2 trillion cubic feet of natural gas, are located adjacent to the Sfax permit. Three significant undeveloped oil discoveries made by previous operators are located on the permit. Eurogas and its partner, APEX, have initiated a program to develop these oil discoveries.

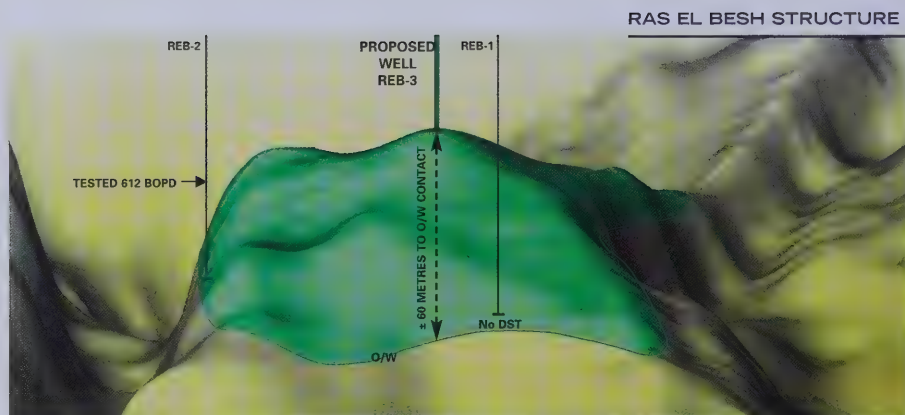
Opposite

Left: Working on the rig.
Right: Drilling in Tunisia,
El Hamra Permit.

EUROGAS PERMITS IN TUNISIA



TUNISIA



Preliminary interpretation of Ras El Besh structure. (Image based on the initial structure stack of 3-D seismic data)

SFAX PERMIT

The Sfax Seismic Prospecting Permit is located in Tunisia's shallow waters in the Gulf of Gabes, offshore and southeast of the city of Sfax. Eurogas holds a 45 percent working interest in this 1.02-million-acre (4,116 km²) permit. Eurogas has identified strong potential to prove up to 350 million barrels of oil-in-place, in the three known oil accumulations, plus a wider resource potential of up to 1.9 billion barrels of oil-in-place. The permit, obtained in December 2003, lies in an established hydrocarbon fairway. The permit is flanked to the northwest, north and east by producing oil and natural gas pools holding reserves of over 500 million barrels of crude oil and 2.2 trillion cubic feet of natural gas.

Eurogas regards the Sfax prospects as medium-risk with high-reward exploration and exploitation potential. The permit contains three known oil pools discovered during the 1970s and 1990s. Despite drill-stem testing at rates of up to 1,850 barrels per day, the three discovery wells were abandoned due to the poor oil economics of the day.

In 2004, Eurogas and its partner reprocessed 500 km of 2-D seismic and shot 350 km² of new 3-D seismic, exceeding our work commitment. The new 3-D seismic program encompasses two of the previously identified pools, plus a wider area that includes four additional leads. A further 10 leads have been identified in other areas of the block. The partners plan to begin drilling in late 2005 or early 2006 after the Seismic Prospecting Permit has been converted to an Exploration Permit.

Given the region's productive history and the previous discoveries on the Sfax block, Eurogas believes it can achieve oil production at an early date. The exploration program's initial focus is to re-drill one of the two identified oil pools. The target zones are within Eocene and Late Cretaceous carbonates at depths down to approximately 2,500 metres. Advances in 3-D seismic acquisition and processing will facilitate optimum placement of the wells, resulting in greater chances of success and higher production rates.

SFAX PERMIT AREA



A production sharing agreement has been negotiated for Sfax. For "Cost Oil" (cash flow from oil production needed to recover project investment costs), the partnership (Eurogas 45 percent and APEX 55 percent) receives 55 percent for production of up to 5,000 bbls per day, reducing to 40 percent for production over 10,000 bbls per day. E.T.A.P., the Tunisian state oil company, receives the balance. The partnership receives 42.5 percent on "Profit Oil" (after payout of project investment costs) for production of up to 5,000 bbls per day, reducing to 25 percent for production over 10,000 bbls per day. E.T.A.P. receives the balance. E.T.A.P. is the permit-holder and is required to pay all taxes, including that of the partnership's, out of E.T.A.P.'s share of production.

TUNISIA



EL HAMRA PERMIT

Eurogas holds a 20 percent interest in the 1.2-million-acre El Hamra permit in southern Tunisia. Work to date by Eurogas and its partners suggests the area is prospective for oil and natural gas. Six prospects and seven additional leads have also been identified on the block.

The El Hamra play is wildcat exploration for very large targets. Recent drilling in central Tunisia has substantiated the regional extension of the primary target formation, the Triassic TAGI sands, from the Berkine Basin into south-central Tunisia. The wells found excellent reservoir quality but did not encounter economic accumulations of oil or natural gas. El Hamra prospects are located much closer to existing producing pools such as El Borma (65 kilometres to the southwest), which contains 965 million barrels of recoverable oil.

A well at El Hamra, EH-1, spudded in late February 2005 and rig-released in mid-March. The primary target is a 13,800-acre-sized TAGI sands structure that could contain up to 850 million barrels of oil-in-place. The region to the south has been the scene of several recent Ordovician discoveries, and accordingly EH-1 drilled into the secondary Ordovician target, with total depth of approximately 3,000 metres. The EH-1 well lies 2.5 kilometres from a crude oil pipeline with available capacity. Eurogas has funded its share of up to \$5.5 million in costs for the well through a farm-out that reduced its interest at El Hamra to 20 percent.

EL HAMRA PERMIT AREA



The El Hamra permit operates under a standard Tunisian contract, which allows the state oil company E.T.A.P. to participate up to 50 percent in any production concession which may be granted. If E.T.A.P. chooses to participate in such production concession, it must bear its share of the development and exploitation expenses, while reimbursing the permit-holder for E.T.A.P.'s share of exploration costs.

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A") provides a discussion and analysis of financial condition and results of operations of Eurogas Corporation ("Eurogas" or the "Corporation") for the year ended December 31, 2004. The following information has been prepared by management in accordance with Canadian generally accepted accounting principles ("GAAP") and should be read in conjunction with the audited consolidated financial statements for the years ended December 31, 2004 and 2003, together with the notes related thereto. This MD&A is based on information available as of April 7, 2005.

Eurogas is a Canadian-based company whose common shares are traded on the TSX Venture Exchange (TSXV). In 2004 Eurogas carried on exploration, development, production and acquisition activities in Spain, Tunisia and Canada. Eurogas is focused on creating long-term value through the development of high-impact energy projects. The Corporation is developing an underground natural gas storage facility in Spain and is conducting exploration programs for oil and natural gas on concessions on- and offshore Tunisia. Additional information relating to the Corporation can be found on the SEDAR website at www.sedar.com or on the Corporation's website at www.eurogascorp.com.

FORWARD-LOOKING STATEMENTS

This MD&A contains forward-looking statements. Forward-looking statements are based upon assumptions and judgements with respect to the future including, but not limited to, the outlook for commodity markets and capital markets, the performance of producing wells and reservoirs, and the regulatory and legal environment. These factors may be difficult to predict. As a result, forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those anticipated.

All financial units in this MD&A are expressed in Canadian dollars unless otherwise stated.

2004 HIGHLIGHTS

- On June 11, 2004 Eurogas transferred, under a Plan of Arrangement, the majority of its Canadian assets into a separate public corporation named Great Plains Exploration Inc. ("Great Plains"). Eurogas retained an interest in two minor, non-operated natural gas-producing properties: Murray Lake in Alberta and Hatton in Saskatchewan (the "retained properties").
- A detailed Design Basis Memorandum (DBM) study was prepared by a joint venture comprised of two internationally recognized engineering firms, AMEC PLC of the U.K. and Tri Ocean Natchiq Engineering Ltd. of Calgary, Canada, to evaluate design alternatives and to ascertain capital and operating costs for the Amposta underground natural gas storage project in Spain.
- On December 14, 2004 Eurogas spudded the Castor #1 appraisal well on the Amposta structure in Spain, and on January 24, 2005 completed drilling and testing operations after flow testing oil in commercial quantities. The total cost of the well was \$13 million, of which \$3.9 million was spent in 2004. Eurogas holds a 72 percent interest in the underground gas storage project and 100 percent interest in any hydrocarbons produced on the permit.
- On the 1-million-acre Sfax permit located offshore in the Gulf of Gabes in Tunisia, Eurogas participated in a 350 km² 3-D seismic program. During the third quarter of 2004, Eurogas and its partner received approval from the Tunisian government for a 105,000-acre addition to the Sfax permit. Eurogas holds a 45 percent working interest in the Sfax permit.

- During the third quarter of 2004, the Corporation farmed-out 60 percent of its 50 percent interest in the El Hamra permit in Tunisia. The Corporation received US\$500,000 from the farmee, which was credited to the Tunisian full-cost pool. The farmee will fund Eurogas' portion of the cost to drill the El Hamra #1 well up to a total well cost of US\$5,000,000, over which Eurogas will be responsible for its 20 percent share. Eurogas retained a 20 percent working interest and will be responsible for 20 percent of any other costs incurred on the permit.
- On December 31, 2004 Eurogas closed a Rights Offering raising \$7,554,368. The fully subscribed share issue allowed shareholders to subscribe to 19,370,778 common shares. The proceeds are being used to finance the Corporation's ongoing drilling and exploration programs in Spain and Tunisia.

CARVE-OUT OF CANADIAN ASSETS

On March 30, 2004 the Board of Directors unanimously approved a plan to reorganize the Corporation through the separation of the Canadian assets and operations and the foreign assets and operations into two separate public companies. The reorganization was approved by the shareholders at Eurogas' Annual General Meeting on April 30, 2004.

The Board of Directors and management of Eurogas believed that the reorganization would serve to enhance shareholder value through more efficient management of the Corporation's diverse assets in Spain, Tunisia and Canada. In the Plan of Arrangement each shareholder of Eurogas Corporation received one new Eurogas Common Share and 0.2 of a Great Plains Common Share, for each Eurogas Common Share held.

As a result of the corporate reorganization, the combined market capitalization of the two companies is greater than market capitalization of the Corporation prior to the carve-out.

After the carve-out of the Canadian assets, Eurogas retained an interest in two minor, non-operated Canadian properties. Net operating revenues from these properties are forecast at less than \$300,000 for 2005 and will decline thereafter.

RESULTS OF OPERATIONS

The following describes the results of operations for the Corporation's two remaining properties for the 12 months ended December 31, 2004. Prior-period comparative numbers have been restated for comparison purposes.

Results of operations for the assets transferred to Great Plains for the 162-day period ended June 10, 2004 are disclosed as discontinued operations in the Corporation's consolidated financial statements.

Oil and Natural Gas Sales

(\$000s)	2004	2003	% change
Gross oil and natural gas liquids sales	\$ –	\$ 1,703	(100)
Gross natural gas sales	1,325	510	159
Royalties	(237)	(578)	(59)
ARTC	53	–	100
Oil and natural gas sales, net of royalties	\$ 1,141	\$ 1,635	(30)

Oil and natural gas sales from continuing operations, net of royalties, decreased by 30 percent year-over-year to \$1,141,438 in 2004. Production volumes on a barrel of oil equivalent basis (boe) (6:1 natural gas to oil) decreased from 169 boe per day in 2003 to 95 boe per day in 2004, reducing sales revenue by \$493,882. The production decrease was primarily due to the sale of oil-producing properties in Saskatchewan during 2003. The decline in oil and natural gas liquids sales was partially offset by an increase in natural gas sales at the Corporation's two production areas, Hatton and Murray Lake.

Oil and natural gas sales from continuing operations decreased by 10 percent from \$225,724 in the third quarter to \$202,438 in the fourth quarter of 2004. The decrease is a result of the 55 percent decline in production over the quarter. This decline was partially offset by an 18 percent increase in the Corporation's realized gas price from \$5.75 per mcf in the third quarter to \$6.77 per mcf in the fourth quarter.

	2004	2003	% change
Oil and natural gas liquids volumes (mbbls)	\$ —	\$ 48	(100)
Oil and natural gas liquids price (\$/bbl)	—	36.20	n/a
Gross oil and natural gas liquids sales (\$000s)	—	1,703	(100)
Natural gas volumes (mmcf)	209	80	161
Natural gas price (\$/mcf)	6.34	6.34	—
Gross natural gas sales (\$000s)	\$ 1,325	\$ 510	159

Natural gas volumes comprised 100 percent of total volumes in 2004, compared to 21 percent on a boe basis in 2003. At year-end 2004, natural gas volumes accounted for 100 percent of the Corporation's production.

Royalties

Total royalties before the Alberta Royalty Tax Credit (ARTC) decreased from \$577,858 in 2003 to \$237,212 in 2004, a decrease of 59 percent. As a percentage of sales, royalties were 18 percent in 2004 compared to 26 percent in 2003. The decrease in royalties as a percentage of oil and natural gas sales is due to the sale in 2003 of oil properties with high Crown royalty rates.

Operating Expenses

Operating expenses decreased from \$370,000 in 2003 to \$302,000 in 2004, a decrease of 18 percent. On a unit-of-production basis, operating costs were \$8.66 per boe in 2004 compared to \$6.03 per boe in 2003, a 44 percent increase. The sale of low-operating-cost production at Cantuar and Ingoldsby in 2003, and the high processing fees associated with the Murray Lake property, contributed to the increase.

Operating expenses decreased by 26 percent from \$59,030 in the third quarter to \$43,787 in the fourth quarter. On a boe basis, operating costs have increased from \$6.62 per boe in the third quarter to \$10.73 in the fourth quarter of 2004. Although there are fewer total operating expenses during the quarter due to reduced gathering and processing costs at the Murray Lake property, the decline in production has resulted in an increase in costs per boe.

GENERAL AND ADMINISTRATIVE (G&A) EXPENSES

(\$000s except per boe)	2004	2003	% change
Total	\$ 704	\$ 596	18
Capitalized	—	(295)	(100)
Expensed	704	300	135

The Corporation's G&A expenses increased by \$404,204 year-over-year to \$704,412 in 2004 from \$300,208 in 2003. Contributing to the annual increase, the Corporation did not capitalize any G&A cost associated with Canadian properties during 2004 (2003 – \$295,360). In addition, \$100,000 debt forgiveness net of taxes was granted at December 31, 2004 and included as a component of salary expense for 2004. No such costs were incurred in 2003.

G&A increased from \$87,016 in the third quarter to \$481,670 in the fourth quarter. The increase over the quarter is the result of \$100,000 debt forgiveness net of taxes granted at the end of the quarter, plus accrual for anticipated year-end administrative costs including bonuses not previously anticipated.

Restructuring Costs

The Corporation incurred restructuring costs of \$297,000 in 2004 related to the transfer of assets to Great Plains pursuant to the Plan of Arrangement. No such costs were incurred in 2003.

Depletion, Depreciation and Accretion

Depletion, depreciation and accretion decreased by 71 percent from \$889,844 in 2003 to \$254,187 in 2004, partly due to the decrease in production in 2004.

Depletion, depreciation and accretion increased by 24 percent from \$65,092 in the third quarter to \$80,559 in the fourth quarter. The increase is a result of an increase in the depletion rate applied to Canadian producing assets during the quarter using independent reserve evaluations performed at December 31, 2004.

Foreign Exchange

The strengthening of the Canadian dollar in relation to the U.S. dollar during 2004 resulted in a foreign exchange loss of \$229,000 on U.S.-denominated short-term cash deposits. The Cdn\$/US\$ exchange rate declined from a December 31, 2003 rate of 1.29 to a December 31, 2004 rate of 1.20.

Discontinued Operations

	2004 (\$000s)	2004 (\$/boe)	2003 (\$000s)	2003 (\$/boe)
Oil and natural gas sales (gross)	\$ 3,480	\$ 35.88	\$ 8,581	\$ 39.31
Royalties	527	5.44	1,437	6.58
Operating costs	854	8.81	1,648	7.55
Operating netbacks	\$ 2,099	\$ 21.63	\$ 5,496	\$ 25.18

Discontinued operations relate to the assets transferred to Great Plains on July 11, 2004. Production from these discontinued assets decreased by 56 percent from 218,309 boe in 2003 to 97,010 boe in 2004. The assets generated revenues for the 162-day period to July 10, 2004 as compared to 365 days in 2003. The decrease in production received by the Corporation in 2004 is the main reason for the decrease in sales. Operating netbacks decreased by 14 percent from \$25.18 per boe in 2003 to \$21.63 per boe in 2004 mainly due to a decrease in revenue per boe in 2004.

RESERVES

Gilbert Laustsen Jung Associates Ltd. (GLJ) of Calgary, Alberta, independent petroleum consultants, have prepared a report wherein GLJ has evaluated, effective December 31, 2004, the quantity and estimated future cash flow of the Corporation's total estimated proved and probable Canadian reserves.

SUMMARY OF RESERVES AND VALUES

(As of December 31, 2004, forecasted prices and costs)	Proved Producing	Total Probable	Total Proved Plus Probable
Marketable Reserves			
Natural Gas (mmcf)			
Working Interest	428	90	518
Net After Royalty	387	83	470
Oil Equivalent (mboe)			
Working Interest	71	15	86
Net After Royalty	65	14	78
Before Tax Present Value (\$000s)			
0%	859	198	1,057
5%	774	141	915
10%	700	104	804
15%	639	79	718
20%	589	62	651

CAPITAL EXPENDITURES

Capital expenditures totalled \$9.3 million in 2004 compared to \$9.9 million in 2003. The Corporation capitalizes all overhead expenses on its international projects as these projects are in the exploratory and pre-development phases.

Spain

Spending in Spain totalled \$5.3 million in 2004 which included re-processing existing 3-D seismic, completing a DBM study, and the 2004 portion of costs for drilling the Castor #1 well. The Castor #1 well was started in 2004 and completed in 2005 for a total cost of \$13 million, \$3.9 million of which was incurred in 2004 and included in Spain capital spending for 2004. In 2003 spending totalled \$2.0 million.

The 2005 capital budget for Spain is estimated to be \$40 million, depending somewhat on the timing of certain events including regulatory approvals in Spain, and will be incurred for the remaining Castor #1 well costs, a new 3-D seismic program, drilling one additional well, and bringing the two wells on-production.

Tunisia

Eurogas spent a total of \$2.5 million on its Tunisia projects in 2004, principally to participate in a 3-D seismic program on the Sfax Permit. The expenditures were offset by receipts of \$1.8 million for a net expenditure of \$0.7 million. In 2003 spending totalled \$2.4 million.

During the first quarter of 2004 the Corporation received US\$0.9 million (Cdn\$1.2 million) which was credited to the Tunisian full-cost pool, fulfilling a Participant's funding obligation relating to a Tunisian exploration drilling program.

During the third quarter of 2004 the Corporation farmed-out 60 percent of its 50 percent interest in the El Hamra permit. The Corporation received US\$500,000 (Cdn\$0.6 million) from the farmee, which was credited to the Tunisian full-cost pool. The farmee will fund Eurogas' portion of the cost to drill the El Hamra #1 well, up to a total well cost of US\$5 million, over which Eurogas will be responsible for its 20 percent share. Eurogas retains a 20 percent working interest and will be responsible for 20 percent of any other costs.

The 2005 capital budget for Tunisia is less than \$1 million and will be used to process and evaluate the 3-D seismic data at Sfax and to fund the Corporation's share of any completion costs for the El Hamra #1 well.

Canada

Capital expenditures relating to oil and natural gas properties were \$3.3 million for 2004, a decrease of 40 percent compared to 2003 expenditures of \$5.5 million. The Corporation was successful in acquiring two substantial parcels of undeveloped land: 1,920 acres at Lodgepole, Alberta and 79,822 acres at Staynor, Saskatchewan. These two land parcels were sold to Great Plains, at the acquisition price of \$2.2 million, as part of the Plan of Arrangement.

LIQUIDITY AND CAPITAL RESOURCES

The Corporation funded its 2004 capital expenditure program from cash flow from operations and existing cash and short-term deposits.

The Corporation has a revolving credit facility with a Canadian chartered bank which on December 31, 2004 provided credit of \$780,000 and bears interest at the bank's prime lending rate plus 0.375 percent per annum. The level of credit is decreased by \$85,000 at the end of every quarter. The facility is secured by the Corporation's Canadian oil and natural gas assets. At December 31, 2004 the full value of the line was used as collateral for letters of guarantee needed for the drilling of the Castor #1 well. As the well is complete, all but \$39,000 of the letters of guarantee are in the process of being cancelled; the remaining guarantees will remain in effect until December 31, 2006.

Subsequent to December 31, 2004 Eurogas established a non-revolving, non-amortizing credit facility with Dundee Corporation for the amount of \$6 million, bearing interest at the rate of prime plus 2 percent per annum. The existing line of credit will be cancelled.

On December 31, 2004 Eurogas closed a rights offering to shareholders to subscribe to 19,370,778 Common Shares at a subscription price of \$0.39 per share. The share issue was fully subscribed, raising a total of \$7,554,368.

At December 31, 2004 the Corporation had a working capital surplus of \$10.2 million. Included in working capital are cash and short-term deposits totalling \$3 million. U.S. dollar-denominated cash and short-term deposits totalled \$1.5 million (US\$1.3 million), with the remaining \$1.5 million held primarily in Canadian funds.

At December 31, 2004 the Corporation's market value of common shares was \$54 million based on the closing price of \$0.56 per share and 96,851,477 shares outstanding. During 2004 Eurogas issued 19.4 million shares through a rights offering and 1.6 million shares through the exercise of options. The number of common shares outstanding at April 7, 2005 has increased by 366,667 to 97,218,144.

The Corporation's total capital program for 2005 is approximately \$40 million, depending somewhat on the timing of certain events, including regulatory approvals in Spain. The Corporation is reviewing financing options which will allow it to meet the requirements of its programs on a timely basis.

Commitments and Contractual Obligations

The Corporation has commenced a 140 km² 3-D seismic survey on the Castor permit in Spain for an estimated cost of \$3.3 million.

BUSINESS RISKS

Commodity Pricing – Future revenues depend on market prices for crude oil and natural gas, which fluctuate from time to time. Adverse fluctuations can have a significant negative effect on the Corporation's revenues.

Exploration Risks – Oil and natural gas exploration involves a high degree of risk, which even a combination of experience, knowledge and careful evaluation may not be able to overcome. There is no assurance that additional oil or natural gas reserves in commercial quantities will be discovered by the Corporation. Eurogas mitigates these risks by employing experienced and qualified people and using sound business practices. The Corporation follows all government regulations, and has an up-to-date emergency response plan. Property and liability insurance in place provides a reasonable amount of protection from risk of loss.

Political Risks – The Corporation experiences risks associated with operations in a number of international locations. These risks can involve matters arising out of government policies, imposition of special taxes or similar charges by government bodies, foreign exchange fluctuations and controls, access to capital markets, civil disturbances, deprivation or unenforceability of contract rights or the taking of property without fair compensation.

Currency Risks – The Corporation's planned capital expenditures are denominated in several currencies, the most important being the Euro and the U.S. dollar, while the Corporation's reporting currency is the Canadian dollar. Fluctuations in the relative value of these currencies can impact the cash available for capital investment.

CRITICAL ACCOUNTING POLICIES

The financial statements have been prepared in accordance with Canadian GAAP. A summary of significant accounting policies are presented in Note 1 to the consolidated financial statements. Certain accounting policies are critical to understanding the financial condition and results of operations of the Corporation. In accounting for oil and natural gas activities there are two choices available under Canadian GAAP: the full-cost or the successful efforts method of accounting.

The Corporation follows the full-cost method of accounting for oil and natural gas activity, whereby all costs related to the exploration for and development of oil and natural gas reserves are accumulated in separate country-by-country cost centres, as described in Note 1 to the consolidated financial statements. Under the full-cost method of accounting, all costs of acquiring, exploring and developing petroleum and natural gas properties and asset retirement costs are capitalized, including unsuccessful drilling costs and administrative costs associated with acquisition and development.

Under the full-cost method of accounting, an impairment test is applied to the overall carrying value of property, plant and equipment, with the estimated reserves valued using estimated future commodity process at period-end.

The Corporation has three cost centres: Spain, Tunisia and Canada. All of the Corporation's production and reserves are associated with the Canadian cost centre.

CRITICAL ACCOUNTING ESTIMATES

The Corporation is currently in the exploratory stage of a drilling program in Tunisia and capitalizes all associated costs. The recovery of the recorded costs is contingent upon the existence of economically recoverable reserves, and future profitable production.

Activities in Spain are in the pre-development phase. All pre-development costs relating to the Castor exploration permit in Spain are capitalized. The recovery of these costs is dependent upon the economic viability of the underground natural gas storage project.

The preparation of financial statements in accordance with Canadian GAAP requires that management make certain judgements and estimates. Due to timing of when activities occur compared to the reporting of those activities, management estimates and accrues operating results and capital spending. Subsequent to the carve-out of Canadian assets to Great Plains, changes in the judgements and estimates related to Canadian properties is not as material as in prior years.

The Corporation calculates asset retirement obligation based on the estimated costs to abandon and reclaim its net ownership interest in all wells and facilities and the estimated timing of the costs to be incurred in future periods. The fair-value estimate is capitalized to property, plant and equipment as part of the cost of the related asset and amortized over its useful life once the asset is operational.

The amounts recorded for depletion and depreciation of oil and natural gas properties and the ceiling test calculation are based on estimates of proved reserves, production rates, oil and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty.

CHANGES IN ACCOUNTING POLICIES

Asset Retirement Obligation

On January 1, 2004 the Corporation retroactively adopted the Asset Retirement Obligation method of accounting for future abandonment and site restoration liabilities for its properties and accrued a \$1.7 million liability in this regard for December 31, 2003. During the year, the asset retirement obligation decreased by \$1.5 million primarily due to the transfer of assets to Great Plains. There was no acquisition or development activity during the year which would require additional asset retirement obligation. As at December 31, 2004, the Corporation's asset retirement obligation was \$179,481.

Full-Cost Accounting in the Oil and Gas Industry – Accounting Guideline AcG-16

Effective January 1, 2004 the Corporation adopted the Canadian Institute of Chartered Accountants' (CICA) Guideline 16, which revises the method in which the Corporation will calculate impairment on its oil and natural gas assets. Based on the revised impairment test as described in the notes to the consolidated financial statements, no impairment existed at December 31, 2004. The Corporation assesses capital asset impairment on an annual basis or when facts indicate that an impairment test may be required.

Transportation Expenses

Effective January 1, 2004 the Corporation adopted the CICA's revised standard Handbook Section 1100. As a result, revenue has been presented prior to transportation costs and a separate expense for transportation costs has been presented in the Consolidated Statements of Operations and Retained Earnings. The Corporation has reclassified prior-period amounts to be consistent with presentation under this new policy.

RECENT CANADIAN ACCOUNTING AND RELATED PRONOUNCEMENTS

Earnings per Share

In July 2004 the CICA proposed to amend Handbook Section 3500 "Earnings per Share" to reflect similar amendments adopted by the International Accounting Standards Board and proposed by the U.S. Financial Accounting Standards Board. The majority of the amendments relate to the treatment of mandatorily convertible instruments. The CICA expects changes to be effective for interim and annual periods relating to fiscal years beginning on or after January 1, 2005. The Corporation does not have any mandatorily convertible instruments and therefore does not expect these amendments to have a material impact on the Corporation.

Changes in Accounting Policies and Estimates, and Errors

The Accounting Standards Board (AcSB) has proposed a new Handbook Section 1506 "Changes in Accounting Policies and Estimates, and Errors" to provide guidance around when and how an entity is permitted to change an accounting policy as well as establish appropriate disclosures to explain the effects of changes in accounting policy, estimates and corrections of errors.

Subsequent Events

The AcSB has proposed to extend the period during which subsequent events are required to be considered. This period is between the balance sheet date and when the financial statements are authorized for issue. Furthermore, disclosure is required as to the date the financial statements were authorized for issue and who provided that authorization.

Other accounting standards issued by the CICA during the year ended December 31, 2004 are not expected to materially impact the Corporation.

2004 QUARTERLY INFORMATION

	Q1	Q2	Q3	Q4	Annual
Financial ⁽¹⁾					
Oil and gas sales, net of royalties	\$ 339,963	\$ 373,313	\$ 225,724	\$ 202,438	\$ 1,141,438
Cash flow from operations	155,398	269,030	72,532	(537,974)	(41,014)
Per share basic and fully diluted	0.01	0.01	0.00	(0.02)	(0.00)
Net earnings (loss)	221,000	188,346	(324,166)	(763,111)	(677,931)
Per share basic and fully diluted	0.00	0.00	(0.00)	(0.01)	(0.01)
Capital expenditures	\$ 2,666,396	\$ 1,208,980	\$ 3,207,416	\$ 2,248,028	\$ 9,330,820
Operating ⁽¹⁾					
Average daily production					
Crude oil and liquids (bbls/d)	—	—	—	—	—
Natural gas (mcf/d)	704	722	597	266	571
Combined (boe/d @ 6:1)	117	120	99	44	95
Average prices					
Crude oil and liquids (\$/bbl)	—	—	—	—	—
Natural gas (\$/mcf)	6.26	6.73	5.75	6.77	6.34

2003 QUARTERLY INFORMATION

	Q1	Q2	Q3	Q4	Annual
Financial ⁽¹⁾					
Oil and gas sales, net of royalties	\$ 497,891	\$ 424,571	\$ 414,676	\$ 298,182	\$ 1,635,320
Cash flow from operations	561,824	164,376	202,048	(239,441)	1,167,689
Per share basic and fully diluted	0.01	0.00	0.00	(0.01)	0.02
Net earnings (loss)	131,694	(846,816)	(31,170)	(361,843)	(1,108,136)
Per share basic and fully diluted	0.00	(0.01)	(0.00)	(0.00)	(0.01)
Capital expenditures	\$ 1,326,297	\$ 475,222	\$ 2,412,510	\$ 1,256,910	\$ 5,470,939
Operating ⁽¹⁾					
Average daily production					
Crude oil and liquids (bbls/d)	164	163	177	27	132
Natural gas (mcf/d)	164	110	104	497	219
Combined (boe/d @ 6:1)	191	181	194	110	169
Average prices					
Crude oil and liquids (\$/bbl)	41.36	35.95	31.92	23.51	36.20
Natural gas (\$/mcf)	6.53	6.45	6.00	6.00	6.34

⁽¹⁾ Tabular information includes results of operations for Eurogas' properties existing at December 31, 2004. Properties transferred to Great Plains as part of the Corporation's restructuring are disclosed as part of results from discontinued operations in the Corporation's consolidated financial statements.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

The accompanying consolidated financial statements, the notes thereto and other financial information contained in this annual report have been prepared by, and are the responsibility of, the management of Eurogas Corporation. These consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles, using management's best estimates and judgements when appropriate.

The Board of Directors is responsible for ensuring that management fulfills its responsibility for financial reporting and internal control. The Audit Committee, which is comprised of directors, none of whom are employees of the Corporation, meets with management as well as the external auditors to satisfy itself that management is properly discharging its financial reporting responsibilities and to review its consolidated financial statements and the report of the auditors. It reports its findings to the Board of Directors, which approves the consolidated financial statements.

The consolidated financial statements have been audited by Ernst & Young LLP, the independent auditors, in accordance with Canadian generally accepted auditing standards. The auditors have full and unrestricted access to the Audit Committee.



Julio Poscente
Chairman of the Board
April 7, 2005



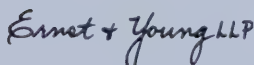
Andrew Constantinidis
Vice President and Chief Financial Officer

AUDITORS' REPORT TO THE SHAREHOLDERS OF EUROGAS CORPORATION:

We have audited the consolidated balance sheets of Eurogas Corporation as at December 31, 2004 and 2003 and the consolidated statements of operations and retained earnings and cash flows for the years then ended. These consolidated financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2004 and 2003 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.



Chartered Accountants
Calgary, Alberta
April 7, 2005

CONSOLIDATED BALANCE SHEETS

As at December 31	2004	2003 (restated – Notes 1 and 2)
ASSETS		
Current		
Cash and short-term deposits	\$ 2,975,897	\$ 9,671,024
Accounts receivable, prepaids and other	1,337,493	2,204,916
Joint venture receivable (Note 5(a))	1,031,820	–
Rights offering proceeds receivable (Note 7(c))	7,554,368	–
	12,899,578	11,875,940
Notes receivable (Note 4)	1,056,000	1,019,938
Oil and gas properties (Note 5)	31,859,468	34,450,936
Future income taxes (Note 10)	95,000	1,368,087
	\$ 45,910,046	\$ 48,714,901
LIABILITIES		
Current		
Accounts payable and accrued liabilities	\$ 2,596,997	\$ 3,044,376
Taxes payable	60,000	–
	2,656,997	3,044,376
Asset retirement obligation (Note 2)	179,481	1,688,600
Non-controlling interest	1,779,000	1,802,000
	4,615,478	6,534,976
Commitments (Note 11)		
SHAREHOLDERS' EQUITY		
Share capital (Note 7)	34,673,661	35,434,728
Contributed surplus (Note 8)	75,556	10,554
Retained earnings	6,545,351	6,734,643
	41,294,568	42,179,925
	\$ 45,910,046	\$ 48,714,901

See accompanying notes.

On behalf of the board



Derek H.L. Buntain
Director



Garth A.C. MacRae
Director

CONSOLIDATED STATEMENTS OF OPERATIONS AND RETAINED EARNINGS

Year ended December 31	2004	2003 (restated – Notes 1 and 2)
REVENUE		
Oil and gas sales, net of royalties	\$ 1,141,438	\$ 1,635,320
Natural gas marketing revenue (Note 3)	–	2,580,771
Interest and other	86,131	157,719
	1,227,569	4,373,810
EXPENSES		
Operating	301,685	369,941
Natural gas purchases (Note 3)	–	2,434,497
General and administrative	704,412	300,208
Interest	16,931	21,774
Restructuring costs (Note 7(a))	297,040	–
Depletion, depreciation, and accretion	254,187	889,844
Exchange loss	228,600	1,391,397
Write-off related to Urengoil Inc. (Note 5(d))	–	200,250
	1,802,855	5,607,911
Loss from continuing operations before income taxes	575,286	1,234,101
Provision for (recovery of) income taxes (Note 10)	89,128	(30,716)
Loss from continuing operations	664,414	1,203,385
Income from discontinued operations, net of income taxes (Note 13)	475,122	2,055,227
Net (loss) earnings	(189,292)	851,842
Retained earnings, beginning of the year	6,734,643	6,385,590
Change in accounting policy (Note 2)	–	(502,789)
Retained earnings, end of the year	\$ 6,545,351	\$ 6,734,643
Earnings (loss) per common share – basic and diluted (Note 1)		
Loss from continuing operations	\$ (0.01)	\$ (0.01)
Income from discontinued operations, net of tax	0.01	0.03
Net (loss) earnings	(0.00)	0.01

See accompanying notes.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Years ended December 31	2004	2003 (restated – Notes 1 and 2)
OPERATING ACTIVITIES		
Loss from continuing operations	\$ (664,414)	\$ (1,203,385)
Depletion, depreciation and accretion expense	254,187	889,844
Stock-based compensation	65,002	10,554
Provision for (recovery of) future income taxes (Note 10)	89,128	(120,971)
Exchange loss	228,600	1,391,397
Charge related to Urengoil Inc.	–	200,250
Cash flow from (used in) continuing operations	(27,497)	1,167,689
Cash flow from discontinued operations	1,460,959	4,299,176
Changes in non-cash working capital (Note 15)	1,300,065	3,891,480
Cash provided by operating activities	2,733,527	9,358,345
FINANCING ACTIVITIES		
Issue of share capital, net of repurchases (Note 7)	7,606,330	84,000
Proceeds on issuance of Partnership units (Note 5(a))	–	285,105
Acquisition of interest in Partnership (Note 5(a))	(44,549)	–
Repayment of bank debt	–	(539,000)
Change in non-cash working capital	(7,468,880)	(56,429)
Cash provided by (used in) financing activities	92,901	(226,324)
INVESTING ACTIVITIES		
Disposition of oil and gas properties (Note 5(c))	51,500	3,387,951
Net investment in oil and gas properties (Note 5)	(9,330,839)	(9,875,795)
Abandonment and site restoration	(13,616)	(114,555)
Cash used in investing activities	(9,292,955)	(6,602,399)
Foreign exchange loss on cash held in foreign currency	(228,600)	(1,391,397)
Increase (decrease) in cash and short-term deposits	(6,695,127)	1,138,225
Cash and short-term deposits, beginning of the year	9,671,024	8,532,799
Cash and short-term deposits, end of the year	\$ 2,975,897	\$ 9,671,024

See accompanying notes.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Years ended December 31, 2004 and 2003

1. SIGNIFICANT ACCOUNTING POLICIES

Eurogas Corporation ("Eurogas" or the "Corporation") is an oil and natural gas company which carries on exploration, development, production and/or acquisition activities in Spain, Tunisia and Canada. These consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and reflect the following policies:

Basis of presentation

Effective June 11, 2004 Eurogas transferred all but two of its major Canadian assets to Great Plains Exploration Inc. ("Great Plains"), pursuant to the Plan of Arrangement described in the Management Information Circular of Eurogas dated April 5, 2004 (the "Arrangement"). The consolidated statements of operations of Eurogas reflect the revenues and expenses of the properties retained by Eurogas for the periods presented. The results of operations of the major Canadian assets transferred to Great Plains are disclosed as discontinued operations for the 162-day period ended June 10, 2004, the date of disposal (see notes 7 and 13).

Comparative numbers presented have been restated to show results of operations related to properties transferred to Great Plains as discontinued operations.

Consolidation

The consolidated financial statements include the accounts of the Corporation and all of its subsidiaries.

Foreign currency translation

The Corporation follows the temporal method in accounting for its integrated foreign operations and translates its foreign-denominated monetary assets and liabilities at the exchange rate prevailing at year-end. Non-monetary assets and liabilities are translated at historic rates. Revenues and expenses are translated at the average rate of exchange for the year. Exchange gains or losses are included in operations.

Financial instruments

The Corporation's financial instruments at December 31, 2004 consist of cash and short-term deposits and income taxes payable, accounts receivable, rights offering proceeds receivable, notes receivable, accounts payable and accrued liabilities. At December 31, 2004 and 2003 the fair value of financial instruments approximated book value due to the near-term maturity or the associated interest rate terms.

In 2003 the Corporation entered into commodity price derivative instruments to reduce the exposure to adverse fluctuations in commodity prices on the value of natural gas inventory. No contracts were entered into for trading or speculative purposes. Gains and losses relating to commodity price derivative instruments that met hedge criteria were recognized as part of natural gas marketing revenue concurrently with the hedged transaction.

The Corporation's policy is to formally designate each commodity price derivative instrument as a hedge of a specifically identified future revenue stream. The Corporation believes the commodity price derivative instruments are effective as hedges, both at inception and over the term of the instrument, as the term to maturity, the notional amount and the commodity price basis in the instruments all match the terms of the future revenue stream being hedged.

Realized and unrealized gains or losses associated with commodity price derivative instruments, which have been terminated or cease to be effective prior to maturity, are deferred as other current or non-current assets or liabilities on the balance sheet,

as appropriate, and recognized in earnings in the period in which the underlying hedged transaction is recognized. In the event a designated hedged item is sold, extinguished or matures prior to the termination of the related commodity price derivative instrument, any realized or unrealized gain or loss on such derivative instrument is recognized in earnings.

Exploration and development expenditures

The Corporation follows the full-cost method of accounting for exploration and development expenditures whereby all costs related to the exploration for and development of oil and natural gas reserves, including asset retirement costs, are accumulated in separate country-by-country cost centres. Costs include lease acquisition, geological and geophysical expenditures, carrying costs of non-productive properties, the drilling of productive and non-productive wells and related plant and production equipment costs, and that portion of general and administrative expenses and interest directly attributable to exploration and development activities. Proceeds received from the disposal of properties are normally deducted from the full-cost pool without recognition of a gain or loss. When such a disposal would alter the depletion and depreciation rate by more than 20 percent, a gain or loss would be recognized.

Pre-development costs

The Corporation is currently in the exploratory stage of drilling programs in Spain and Tunisia and capitalizes all costs associated with these programs. The recovery of the recorded costs is contingent upon the existence of economically recoverable reserves, and future profitable production.

Ceiling test

Effective January 1, 2004 the Corporation adopted the Canadian Institute of Chartered Accountants' ("CICA") new accounting guideline related to full-cost accounting. Under the new guideline, future net revenues from total proved reserves used in the ceiling test calculation are estimated using expected future product prices and costs (escalating), whereas prior to the adoption, constant pricing was used. Future general and administrative, and financing charges, associated with the future net revenues are no longer deducted in arriving at the ceiling value. Impairment is recognized when the carrying amount is greater than the undiscounted future net revenue, at which time assets are written down to the fair value of proved and probable reserves plus the costs of unproved properties, net of impairment allowances.

The adoption of the new guideline has resulted in no change to net income, fixed assets or other reported amounts in the consolidated financial statements.

Joint ventures

Substantially all of the Corporation's exploration, development and production activities are conducted jointly with other entities and accordingly the consolidated financial statements reflect only the Corporation's proportionate interest in such activities.

Revenue recognition

Oil and natural gas sales are recognized when title passes to an external party.

Transportation expenses

Effective January 1, 2004 the Corporation adopted the CICA's revised Handbook Section 1100 "Generally Accepted Accounting Principles". As a result, revenue has been presented prior to transportation costs which have been included as a component of expenses in the Consolidated Statements of Operations and Retained Earnings. The Corporation has reclassified prior-period amounts to be consistent with presentation under this new policy.

Depletion and depreciation

Depletion of oil and natural gas properties and equipment is computed using the unit-of-production method where the ratio of production to proved reserves, before royalties, determines the proportion of depletable costs to be expensed. Undeveloped properties are excluded from the depletion calculation until quantities of proved reserves are found or impairment occurs. Volumes are converted to equivalent units using the ratio of one barrel of oil to six mcf of natural gas. Depreciation of office equipment and computer equipment is provided for on a 10 percent and 35 percent straight-line basis, respectively.

Asset retirement obligation

The Corporation has adopted the CICA standard for accounting for asset retirement obligation. This standard requires that the fair value of the legal obligation associated with the retirement and reclamation of tangible long-lived assets be recorded when the obligation is incurred, with a corresponding increase to the carrying amount of the related assets. This corresponding increase to capitalized costs is amortized to earnings on a basis consistent with depreciation, depletion and amortization of the underlying assets. Subsequent changes in the estimated fair value of the asset retirement obligation are capitalized and amortized over the remaining useful life of the underlying asset. The asset retirement obligation liabilities are carried on the consolidated balance sheet at their discounted present value and are accreted over time for the change in their present value.

Measurement uncertainty

The amounts recorded for depletion and depreciation of oil and natural gas properties, the asset retirement obligation and the ceiling test calculation are based on estimates of proved reserves, production rates, oil and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the consolidated financial statements of changes in such estimates in future years could be significant.

Stock-based compensation

The Corporation recognizes stock-based compensation expense using the fair value method when stock options with no cash settlement features are granted to employees and directors under the fixed share option plan. Under this method, compensation expense is measured at the grant date and recognized as a charge to earnings over the vesting period with a corresponding credit to contributed surplus. The fair value of the options is determined using the Black-Scholes option pricing model. Upon the exercise of the options, consideration paid by employees or directors together with the amount previously recognized in contributed surplus is recorded as an increase to share capital. The Corporation adopted the new standard effective January 1, 2003.

Income taxes

The Corporation currently earns revenue only in Canada. All international projects are in the pre-production stage of development and capitalized costs to date will be available for deduction for income tax purposes in the respective jurisdictions, once commercial operations commence.

The Corporation follows the liability method of accounting for income taxes. Under this method, future tax assets and liabilities are determined based on differences between the financial reporting and tax bases of assets and liabilities, and measured using the substantively enacted tax rates and laws that will be in effect when the differences are expected to reverse. The effect on future tax assets and liabilities of a change in tax rates is recognized in income in the period in which the change occurs. The future income tax assets are evaluated and if realization is not considered more likely than not, a valuation allowance is provided.

Cash and short-term deposits

Cash and short-term deposits consist of cash and short-term deposits with a maturity of less than 90 days. The interest rate earned on the short-term deposits varies from 0.4 percent to 1.0 percent per annum. At December 31, 2004 the balance of short-term deposits was nil (December 31, 2003 – \$2,843,280).

Per share information

Basic earnings per common share are computed by dividing the net earnings available to common shareholders by the weighted average number of common shares outstanding during the period (2004 – 76,244,832; 2003 – 75,770,332). Diluted earnings per common share are calculated using the treasury stock method to determine the dilutive effect of stock options. The treasury stock method assumes that the proceeds received from the exercise of “in-the-money” stock options are used to repurchase common shares at the average market price during the year. The diluted weighted average common shares for 2004 are 79,651,297 (2003 – 77,141,981).

Disclosure of guarantees

In accordance with the CICA's Accounting Guideline 14, the Corporation has disclosed all material guarantees issued to third parties.

2. CHANGES IN ACCOUNTING POLICY

Asset Retirement Obligation

On January 1, 2004 the Corporation adopted the new standard of CICA Section 3110, Asset Retirement Obligation. This standard requires the present value of the expected future abandonment and reclamation costs to be recorded on the balance sheet as both a liability and a charge to oil and natural gas properties at the time the obligation is incurred (the completion of drilling). The amount included as oil and natural gas properties is depleted over the life of the reserves by the unit-of-production method. The liability accretes until the Corporation settles the retirement obligation. Actual reclamation and abandonment costs incurred are charged against the liability, with a gain or loss recorded for the difference between the actual costs and the accreted value of the obligation at the time of reclamation. Previously, estimated future abandonment and reclamation costs were provided for over the life of the reserves by the unit-of-production method.

This new standard has been applied retroactively. The impact on the December 31, 2003 balance sheet is as follows:

	As previously reported	Change	As restated
BALANCE SHEET			
Oil and gas properties	\$ 33,997,548	\$ 453,388	\$ 34,450,936
Future income tax asset	1,249,731	118,356	1,368,087
Asset retirement obligation	893,339	795,261	1,688,600
Retained earnings	6,958,160	(223,517)	6,734,643
INCOME STATEMENT			
Depletion, depreciation and accretion	2,234,094	(427,151)	1,806,943
Depletion, depreciation and accretion from discontinued operations (Note 13)	(1,336,129)	(419,030)	(917,099)
Depletion, depreciation and accretion from continuing operations	897,965	(8,121)	889,844
Provision for income taxes	1,169,754	147,879	1,317,633
Provision for income taxes from discontinued operations (Note 13)	(1,200,470)	(147,879)	(1,348,349)

The opening retained earnings as of January 1, 2003 has been reduced by \$502,789 as a result of the retroactive application of the new accounting standard. A credit-adjusted risk-free rate of 5 percent per annum and an annual inflation rate of 2 percent were used to calculate the fair value of the asset retirement obligation.

A reconciliation of the asset retirement obligation is provided below:

	2004	2003
Asset retirement obligation		
Balance, beginning of year	\$ 1,688,600	\$ 1,385,325
Revisions in estimated cash flows	(51,531)	—
Liabilities incurred in the year	—	348,578
Liabilities settled in the year	(13,615)	(114,555)
Accretion expense	46,280	69,252
Liabilities carved out to Great Plains	(1,490,253)	—
Balance, end of year	\$ 179,481	\$ 1,688,600

As at December 31, 2004 the Corporation estimated the total undiscounted amount of cash flow required to settle its asset retirement obligation is approximately \$0.5 million, which will be incurred between 2011 and 2026.

Recovery of Capitalized Costs

On January 1, 2004 the Corporation adopted the new CICA Full Cost Accounting Guideline AcG-16, Oil and Gas Accounting – Full Cost, which replaces AcG-5 Full Cost Accounting in the oil and gas industry. This guideline recognizes impairment when the carrying amount of the oil and natural gas properties, by cost centre, exceeds their undiscounted future cash flows based on estimated future commodity prices. If impairment is recognized, the amount of impairment is determined as the excess of the carrying amount over the fair value. Fair value is based on the present value of expected cash flows, reflecting discounting at the risk-free rate of interest. Both proved and probable reserves are used in estimating fair value. This cost centre impairment test is conducted as at each annual balance sheet date. Previously, the “cost ceiling” limited the net book value of the oil and natural gas properties, by cost centre, to the undiscounted and unescalated future net revenues from production of proved reserves. The application of the new accounting guideline had no impact on the Corporation’s consolidated financial statements.

3. NATURAL GAS MARKETING REVENUE

During 2003 the Corporation purchased natural gas and immediately entered into binding contracts to sell the natural gas to various industry purchasers. The natural gas was stored in the Cantuar gas storage facility in Saskatchewan and was delivered during 2003. At December 31, 2003 the Corporation had fulfilled all of its delivery commitments.

4. NOTES RECEIVABLE

During 2002 the Corporation advanced funds aggregating \$922,547 to certain unit holders of the Castor UGS Limited Partnership (see Note 5(a)). The advances bear interest at 6 percent per annum, are secured by promissory notes and the respective partnership interests, and are repayable by August 1, 2012. Accrued interest of \$133,453 has been included in the balance as at December 31, 2004 (2003 – \$79,464). The fair value of the notes approximate the carrying value as reported on the balance sheet.

5. OIL AND NATURAL GAS PROPERTIES

Following are the Corporation’s oil and natural gas properties by cost centre:

	2004	2003
Spain	\$ 13,873,954	\$ 8,498,975
Tunisia	17,479,155	16,843,407
Canada	506,359	9,108,554
	\$ 31,859,468	\$ 34,450,936

The capital investment during the year by cost centre was as follows:

	2004	2003
Spain	\$ 5,310,293	\$ 1,994,048
Tunisia	736,504	2,372,956
Canada	3,284,042	5,508,791
	\$ 9,330,839	\$ 9,875,795

a) Spain

The Corporation holds a majority interest in the Castor Exploration Permit through Castor UGS Limited Partnership, which was formed in 2001. The Castor Exploration Permit covers the abandoned Amposta oilfield, which is suitable for development as a natural gas storage facility. In January 2003 an additional 170,722 units in the Castor UGS Limited Partnership were issued by the Partnership to new unit holders for cash consideration of \$285,105. In September 2004 the Corporation increased its interest in the Partnership from 71 percent to 72 percent through the purchase of units from a minority interest owner for \$44,549. At December 31, 2004 the Corporation owned 72 percent of the partnership units.

Costs related to the Amposta natural gas storage project in Spain have been capitalized as part of oil and natural gas properties, consistent with prior years. Minority unit holders were cash-called for costs totalling \$1,031,820, which represents the minority unit holders' portion of costs incurred by Eurogas up to and including December 31, 2004. Minority unit holders may choose not to pay the cash call. In that case, their interest in the project will be proportionately reduced. Any unpaid cash call amounts will be added to oil and natural gas properties and the Corporation's interest in the project increased accordingly.

Associated with the natural gas storage project, the Corporation commenced drilling operations during the year to determine the extent of oil that should be removed from crestal positions in the structure ("attics") prior to its use as a storage facility. Under an agreement held with minority unit holders, a subsidiary of the Corporation, Eurogas International Inc., or its designee, has agreed to pay 100 percent of hydrocarbon development costs. In exchange Eurogas will receive a 100 percent (subject to a 5 percent gross over-riding royalty payable to Castor UGS LP) in all hydrocarbons produced from the reservoir.

b) Tunisia

In 2001 the Corporation entered into an agreement with another company ("Participant") whereby the Participant agreed to fund US\$5.2 million of the costs of an exploration drilling program. The balance remaining of US\$910,000 (Cdn\$1.2 million) was received by the Corporation in January 2004, fulfilling the Participant's funding obligation. The amount received was credited to the Tunisian full-cost pool.

In September 2004 the Corporation farmed-out 60 percent of its 50 percent interest in the El Hamra area. The Corporation received US\$500,000 (Cdn\$645,000) from the farmee, which was credited to the Tunisian full-cost pool. The farmee will fund Eurogas' portion of the cost to drill the El Hamra #1 well, up to a well cost of US\$5 million, over which Eurogas will be responsible for its 20 percent share. Eurogas retained a 20 percent working interest and will be responsible for 20 percent of any other costs.

c) Canada

At December 31, 2004 the net book value of Canadian oil and natural gas properties was \$506,359 (2003 – \$9,108,554) after deducting accumulated depreciation and depletion of \$1,185,883 (2003 – \$26,853,774).

At December 31, 2004 oil and natural gas properties include no amount (2003 – \$1,094,487) relating to unproved properties which have been excluded from the depletion and ceiling test calculations. No future development costs (2003 – \$573,000) relating to proved undeveloped reserves are included in the depletion and ceiling test calculations.

Effective June 11, 2004 the Corporation transferred the majority of its Canadian assets to Great Plains as described in Note 2 with the Corporation recording the results of operations of its interest for the period up to June 11, 2004. In addition, during the year the Corporation sold minor interests for proceeds totalling \$51,500.

Effective July 1, 2003 the Corporation sold its interests in the East Cantuar area for cash considerations, net of adjustments, of \$2,270,371. The sale closed on September 24, 2003 with the Corporation recording the results of operations of its interests for the period up to September 24, 2003.

Effective November 1, 2003 the Corporation sold its interest in the Ingoldsby area for cash consideration, net of adjustments, of \$1,337,625. The sale closed on November 21, 2003 with the Corporation recording the results of operations of its interest in the property for the period up to November 21, 2003.

The following table describes prices used for purposes of the Corporation's ceiling test evaluation at December 31, 2004⁽¹⁾:

	Crude Oil		Natural Gas	Natural Gas Liquids
Year	WTI (US\$/bbl)	Edmonton Par Price (Cdn\$/bbl)	AECO (Cdn\$/mmbtu)	(Cdn\$/bbl)
2005	42.00	50.25	6.60	40.08
2006	40.00	47.75	6.35	38.00
2007	38.00	45.50	6.15	36.25
2008	36.00	43.25	6.00	34.50
2009	34.00	40.75	6.00	32.50
2010-2015	33.50	40.09	6.10	31.96
Remainder ⁽²⁾	2.0%	2.0%	2.0%	2.0%

Notes:

⁽¹⁾ GLJ's January 1, 2005 forecasted prices; future prices incorporated a \$0.82 US/Cdn exchange rate.

⁽²⁾ Percentage change of 2.0 percent represents the change in future prices in each year after 2015 to the end of the reserve life.

Included in the Corporation's oil and natural gas properties balance is \$142,070, net of accumulated depletion, relating to the asset retirement obligation.

The Corporation has capitalized no general and administrative expenses (2003 – \$295,360) as part of its Canadian oil and natural gas properties.

d) Russia

During 2002 the Corporation received additional proceeds of \$4,652,816 (US\$3,000,000) in connection with the 2000 sale of all of its shares in Yamalo, a wholly-owned subsidiary which held a 50 percent interest in Urengoil, a Russian joint stock company. In 2004 the Corporation paid outstanding commissions of \$200,250 (US\$150,000) relating to this sale. The amount was accrued in the December 31, 2003 consolidated statement of operations.

6. SEGMENTED INFORMATION

All activities of the Corporation are concentrated in petroleum and natural gas exploration and development with all operating revenues to date earned in Canada. The total identifiable assets by geographic area are as follows:

	2004	2003
Spain	\$ 16,342,472	\$ 8,951,284
Tunisia	17,479,155	16,843,407
Canada	12,088,419	22,920,210
	\$ 45,910,046	\$ 48,714,901

7. SHARE CAPITAL

	Number of Shares	Amount
AUTHORIZED:		
An unlimited number of common and first preference shares, issuable in series		
ISSUED AND FULLY PAID:		
Common shares, December 31, 2002	75,682,181	\$ 35,350,728
Exercise of share options	250,000	84,000
Common shares, December 31, 2003	75,932,181	35,434,728
Exercise of share options	1,550,000	124,000
Less carve-out to Great Plains (a)	—	(8,467,397)
Repurchase of common shares	(1,482)	(904)
Rights offering (c)	19,370,778	7,483,234
Forgiveness of share purchase loan (b)	—	100,000
Common shares, December 31, 2004	96,851,477	\$ 34,673,661

- a) Effective June 11, 2004 the Corporation transferred all but two of its major Canadian assets to Great Plains, pursuant to the Arrangement. Each shareholder of the Corporation received one new Eurogas common share and 0.2 of a Great Plains common share for each Eurogas common share held immediately prior to the Arrangement. The Arrangement also resulted in a reduction in the stated capital of the Corporation as the transaction was effectively a distribution of a portion of the business to the shareholders. Accordingly, share capital of the Corporation has been reduced to reflect this carve-out. The reduction in share capital of \$8,467,397 represents the net investment by the Corporation in the Great Plains net assets for the period up to June 10, 2004. The Corporation incurred restructuring costs of \$297,040 related to this transaction.

As the separation of the major Canadian assets into Great Plains represented a related-party transaction not in the normal course of operations involving two companies under common control, the transaction has been accounted for at net book value as follows:

Amounts transferred to Great Plains:

Working capital	\$ 480,287
Oil and gas properties	10,665,280
Future income tax asset	956,419
Asset retirement obligation	(1,490,253)
	10,611,733
Amount due from Great Plains	2,144,336
Carve-out of share capital	8,467,397
	\$ 10,611,733

- b) On May 30, 1997 the shareholders of the Corporation approved an arrangement whereby the then Chairman and Chief Executive Officer of the Corporation purchased 1,000,000 common shares of the Corporation at a price of \$1.00 per share. The Corporation agreed to provide this officer with a non-interest-bearing loan of \$1,000,000 to finance the purchase. At December 31, 2004 the Corporation forgave \$100,000 of the outstanding debt. This amount has been added to share capital and the debt forgiveness is recorded as compensation expense. The \$900,000 remaining balance of the loan continues to be deducted from share capital. As a result of the carve out – to Great Plains, the loan is now secured by a

pledge of 1,000,000 common shares of the Corporation and 200,000 shares of Great Plains and is repayable out of the proceeds of any sale of the common shares.

- c) On December 31, 2004 Eurogas closed the Offer of Rights to shareholders to subscribe to 19,370,778 common shares at a subscription price of \$0.39 per share. The share issue was fully subscribed, raising a total \$7,554,368 which is being used to finance the Corporation's ongoing drilling and exploration programs in Spain and Tunisia. Costs of the offering of \$71,134 have been recorded on a net-of-tax basis as a reduction of share capital.

8. SHARE OPTION PLAN

The Corporation has established a share option plan under which directors, officers, employees and consultants can be granted options to purchase common shares of the Corporation. The number of shares issuable under the plan cannot exceed 7,500,000 in total, and the number of shares issuable to any one person under the plan cannot exceed 5 percent of the total number of common shares outstanding from time to time. The exercise price of each option equals the market price of the Corporation's stock on the date of the grant and the option's term ranges from five to ten years. A summary of the status of the share option plan is as follows:

	2004		2003	
	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price
Opening	5,075,000	\$ 0.19	5,300,000	\$ 0.41
Granted	400,000	0.32	100,000	0.57
Exercised	(1,550,000)	(0.08)	(250,000)	(0.34)
Cancelled	(133,333)	(0.67)	(75,000)	(0.38)
	3,791,667	\$ 0.24	5,075,000	\$ 0.41

Holders of options to purchase pre-carve-out Eurogas common shares exchanged each of those options for 0.2 Great Plains options at an exercise price based on the volume-weighted average trading price of the Great Plains common shares for the first 10 trading days after the effective date of the carve-out and one new Eurogas option priced on an equalization basis whereby the sum of the exercise prices for one Eurogas share plus one-fifth of a Great Plains share was equal to the original option exercise price. Consequently, the option exercise price was reduced by \$0.22 for all outstanding Eurogas options.

At December 31, 2004 options to purchase 3,525,000 common shares (2003 – 4,458,333) were exercisable as follows:

Price (\$)	Options Outstanding	Options Exercisable	Remaining Contractual Life (Years)
0.15	50,000	50,000	0.3
0.16	1,325,000	1,325,000	2.5
0.18	1,650,000	1,650,000	1.2
0.32	400,000	133,333	4.6
0.35	66,667	66,667	3.2
0.49	150,000	150,000	1.7
0.78	100,000	100,000	2.0
1.59	50,000	50,000	1.2
	3,791,667	3,525,000	

Total compensation expense is amortized over the vesting period of the option. An annual compensation expense of \$65,002 has been recognized in 2004 (2003 – \$10,554) based on the estimated fair value of the options on the grant date in accordance with the fair value method of accounting for stock-based compensation.

The estimated fair value of share options issued during the year was determined using the Black-Scholes model using the following weighted-average assumptions:

	2004	2003
Risk-free interest rate	5.0%	4.5%
Expected hold period to exercise	5 years	5 years
Volatility in the price of the Corporation's shares	107.7%	76.4%
Dividend yield	0.00%	0.00%

9. BANK DEBT

The Corporation has a revolving credit facility of \$780,000 with a Canadian chartered bank, which bears interest at the bank's prime lending rate plus 0.375 percent per annum and has a standby fee of 0.25 percent per annum on undrawn amounts. At December 31, 2004 the Corporation has provided a letter of guarantee for €450,000 (Cdn\$733,000) to the Dirección General De Costas in Spain. This guarantee is provided in connection with the Corporation's drilling of a well offshore Spain in respect of the development of the Amposta natural gas storage facility. Additional smaller guarantees totalling \$138,000 are also outstanding at December 31, 2004. The revolving credit facility is therefore fully utilized to support guarantees.

Interest expense and related standby fees related to the bank loan totalled \$4,912 in 2004 (2003 – \$20,281). Cash interest paid during the years ended December 31, 2004 and 2003 approximates interest expense in each year.

10. INCOME TAXES

Provision for (recovery of) taxes:	2004	2003
Current tax	\$ –	\$ –
Future tax	89,128	(120,971)
Capital tax	–	90,255
	\$ 89,128	\$ (30,716)

The Corporation's future Canadian income tax assets are as follows:

	2004	2003
Temporary differences related to:		
Oil and gas properties	\$ 5,000	\$ 886,857
Share issue costs	20,000	–
Asset retirement obligation	70,000	481,230
	\$ 95,000	\$1,368,087

At December 31, 2004 the Corporation has exploration and development costs and undepreciated capital costs available for deduction against future taxable income for Canadian Tax purposes of approximately \$550,000.

The provision for (recovery of) income taxes differs from the amount computed by applying the combined Canadian federal and provincial tax rate of 38.87 percent (2003 – 40.62 percent) to the loss from continuing operations before taxes of \$575,286 in 2004 (2003 – \$1,234,101). The difference results from the following:

	2004	2003
Computed expected provision for (recovery of) taxes	\$ (223,614)	\$ (501,292)
Effect on taxes of:		
International operations	129,106	81,342
Non-deductible Crown royalties, net of ARTC	34,861	184,479
Resource allowance	(20,648)	(132,946)
Other differences	–	2,671
Reduction in tax pool balances due to reassessments	–	175,155
Non-deductible restructuring costs	82,195	59,702
Resource rate adjustments	87,228	–
Rate adjustment	–	9,918
Income tax provision	89,128	(120,971)
Current taxes	–	–
Future taxes	89,128	(120,971)
Capital taxes	–	90,255
Provision for (recovery of) taxes	\$ 89,128	\$ (30,716)

The Corporation currently earns revenue only in Canada. The adjustments for international operations are related to the charge (recovery of amounts written off) related to Urengoil Inc. These adjustments are not taxable in Canada (see Note 5).

International operations are considered pre-production costs and therefore not subject to tax.

Cash taxes paid during the years ended December 31, 2004 and 2003 approximate capital tax expense in each year.

11. COMMITMENTS

Spain

At December 31, 2004 the Corporation had provided a letter of guarantee for €450,000 (Cdn\$733,000) to a third party in Spain. This guarantee is provided in connection with the Corporation's drilling of the Castor #1 well. Additional smaller guarantees totalling \$138,000 are also outstanding at December 31, 2004.

The Corporation has commenced a 140 km² 3-D seismic survey on the Castor permit in Spain for an estimated cost of \$3.3 million.

Canada

Pursuant to the Corporation's office lease arrangements, \$75,000 is required over the remaining term of the lease which expires on December 31, 2005.

12. RELATED-PARTY TRANSACTIONS

During 2004 \$150,000 (2003 – \$150,000) was paid to a management corporation which remunerated the Chairman of the Corporation for his services.

13. DISCONTINUED OPERATIONS

Results of Discontinued Operations:	2004	2003
REVENUE		
Oil and gas sales, net of royalties	\$ 2,952,515	\$ 7,143,790
Interest and other	(2,554)	—
	2,949,961	7,143,790
EXPENSES		
Operating	854,185	1,647,688
General and administrative	559,751	1,163,927
Interest	3,026	11,500
Depletion, depreciation, and accretion	773,896	917,099
	2,190,858	3,740,214
Earnings from discontinued operations before provision for income taxes	759,103	3,403,576
Provision for taxes	283,918	1,348,349
Discontinued operations, net of tax	\$ 475,185	\$ 2,055,227

At December 31, 2003 the following amounts related to Discontinued Operations were included on the Corporation's balance sheet:

Accounts receivable	\$ 1,653,614
Oil and gas properties	8,208,555
Future income taxes	1,277,727
	11,139,896
Accounts payable and accrued liabilities	1,584,953
Asset retirement obligation	1,466,146
	3,051,099
Net investment	\$ 8,088,797

14. COMPARATIVE FIGURES

Certain comparative figures have been reclassified to conform to the current year's presentation.

15. SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

Changes in non-cash working capital were comprised of the following:

	2004	2003
Accounts receivable	\$ 3,028,248	\$ 1,944,694
Joint venture receivable	(1,031,820)	—
Accounts payable and accrued liabilities	(249,926)	1,946,786
Discontinued operations	(446,437)	—
Net change	\$ 1,300,065	\$ 3,891,480

16. SUBSEQUENT EVENT

During April 2005, Eurogas established a non-revolving, non-amortizing credit facility with Dundee Corporation for the amount of \$6 million bearing an interest rate of prime plus 2 percent per annum. The existing line of credit will be cancelled.

CORPORATE INFORMATION

DIRECTORS

Julio Poscente⁽²⁾

Chairman of the Board
Calgary, Canada

Ned Goodman⁽¹⁾⁽²⁾

Vice Chairman of the Board
Toronto, Canada

M. Jaffar Khan

President & Chief Executive Officer
London, England

Jonathan Goodman

Toronto, Canada

Garth A.C. MacRae⁽¹⁾⁽²⁾

Toronto, Canada

Derek H.L. Buntain⁽¹⁾⁽²⁾

George Town, Cayman Islands

R. James Kirker

Calgary, Canada

(1) Audit Committee

(2) Compensation Committee

OFFICERS

M. Jaffar Khan

President & Chief Executive Officer

Bruce W. Sherley

Executive Vice President
& Chief Operating Officer

Andrew E.W. Constantinidis

Vice President
& Chief Financial Officer

Jim Batchelor

Vice President, Exploration

Donald R. Leitch

Corporate Secretary

AUDITORS

Ernst & Young LLP

BANKERS

Scotiabank
Dundee Corporation

RESERVES ENGINEERS

Gilbert Laustsen Jung Associates Ltd.

LEGAL COUNSEL

Carscallen Lockwood LLP

TRANSFER AGENT AND REGISTRAR

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